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Assumptions to the Annual Energy Outlook 2011

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Introduction

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This report presents the major assumptions of the National Energy Modeling System (NEMS) used to generate the projections in the *Annual Energy Outlook2011* [1] (*AEO2011*), including general features of the model structure, assumptions concerning energy markets, and the key input data and parameters that are the most significant in formulating the model results. Detailed documentation of the modeling system is available in a series of documentation reports [2].

The National Energy Modeling System

The projections in the *AEO2011* were produced with the (NEMS), which is developed and maintained by the Office of Energy Analysis of the Energy Information Administration (EIA) to provide projections of domestic energy-economy markets in the long term and perform policy analyses requested by decisionmakers at the White House, U.S. Congress, offices within the Department of Energy (DOE), including DOE Program Offices, and other government agencies. The *Annual Energy Outlook* (*AEO*) projections are also used by analysts and planners in other government agencies and outside organizations.

The time horizon of NEMS is approximately 25 years, the period in which the structure of the economy and the nature of energy markets are sufficiently understood that it is possible to represent considerable structural and regional detail. Because of the diverse nature of energy supply, demand, and conversion in the United States, NEMS supports regional modeling and analysis in order to represent the regional differences in energy markets, to provide policy impacts at the regional level, and to portray transportation flows. The level of regional detail for the end-use demand modules is the nine Census divisions. Other regional structures include production and consumption regions specific to oil, natural gas, and coal supply and distribution, the North American Electric Reliability Council (NERC) regions and subregions for electricity, and the Petroleum Administration for Defense Districts (PADDs) for refineries. Maps illustrating the regional formats used in each module are included in this report. Only selected regional results are presented in the *AEO2011*, which predominately focuses on the national results. Complete regional and detailed results are available on the EIA Analyses and Projections Home Page (http://www.eia.gov/forecasts/aeo/)

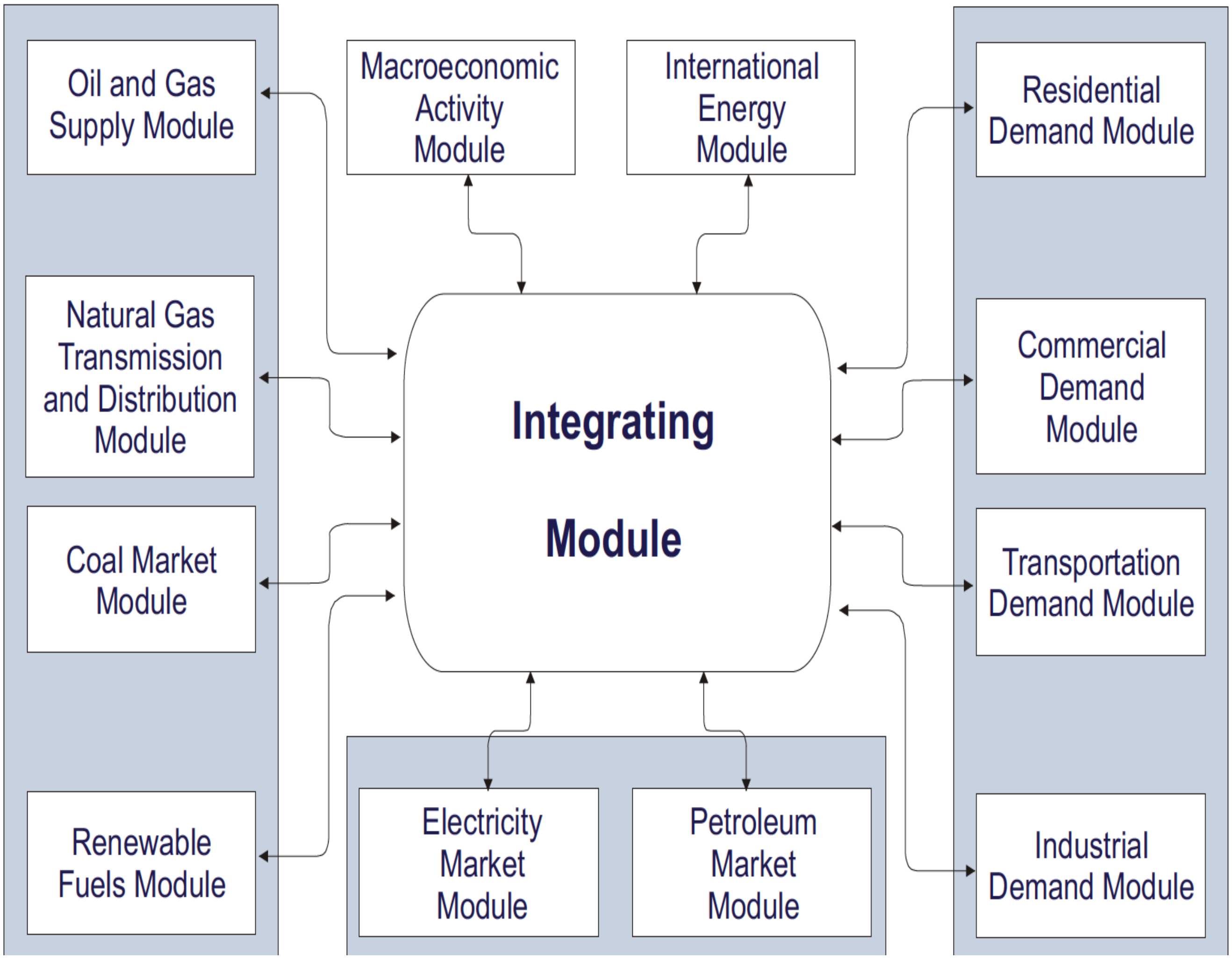
For each fuel and consuming sector, NEMS balances the energy supply and demand, accounting for the economic competition between the various energy fuels and sources. NEMS is organized and implemented as a modular system (Figure 1). The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. NEMS also includes a macroeconomic and an international module. The primary flows of information between each of these modules are the delivered prices of energy to the end user and the quantities consumed by product, region, and sector. The delivered prices of fuel encompass all the activities necessary to produce, import, and transport fuels to the end user. The information flows also include other data such as economic activity, domestic production, and international petroleum supply availability.

The integrating module of NEMS controls the execution of each of the component modules. To facilitate modularity, the components do not pass information to each other directly but communicate through a central data storage location. This modular design provides the capability to execute modules individually, thus allowing decentralized development of the system and independent analysis and testing of individual modules. This modularity allows use of the methodology and level of detail most appropriate for each energy sector. NEMS solves by calling each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors. Solution is reached annually through the projection horizon. Other variables are also evaluated for convergence such as petroleum product imports, crude oil imports, and several macroeconomic indicators.

Each NEMS component also represents the impact and cost of Federal legislation and regulations that affect the sector and reports key emissions. The version of NEMS used for AEO2011 represents current legislation and environmental regulations as of January 31, 2011, such as: the October 13, 2010, U.S. Environmental Protection Agency (EPA) waiver that allows the use of E15 in light-duty vehicles (LDVs) built in 2007 or later; EPA guidelines regarding compliance of surface coal mining operations in Appalachia, issued on April 1, 2010; the American Recovery and Reinvestment Act (ARRA), which was enacted in mid-February 2009; the Energy Improvement and Extension Act of 2008 (EIEA2008), signed into law on October 3, 2008; the Food, Conservation, and Energy Act of 2008; and the Energy Independence and Security Act of 2007 (EISA2007), signed into law on December 19, 2007. The *AEO2011* models do not represent the Clean Air Mercury Rule (CAMR), which was vacated and remanded by the D.C. Circuit Court of the U.S. Court of Appeals on February 8, 2008, but it does represent State requirements for reduction of mercury emissions.

The *AEO2011* Reference case reflects the temporary reinstatement of the nitrous oxide (NOx) and sulfur dioxide (SO2) cap-and-trade programs included in the Clean Air Interstate Rule (CAIR) as a result of the ruling issued by the United States Court of Appeals for the District of Columbia on December 23, 2008. The potential impacts of proposed Federal and State legislation, regulations, or standards—or of sections of legislation that have been enacted but require funds or implementing regulations that have not been provided or specified—are not reflected in NEMS. However, many pending provisions are examined in alternatives cases included in *AEO2011* or in other analyses completed by EIA. A list of the specific Federal and selected State legislation and regulations included in the *AEO*, including how they are incorporated, is provided in Appendix A.

Figure 1. National Energy Modeling System



Source: U.S. Energy Information Administration, Office of Energy Analysis

Component Modules

The component modules of NEMS represent the individual supply, demand, and conversion sectors of domestic energy markets and also include international and macroeconomic modules. In general, the modules interact through values representing the prices of energy delivered to the consuming sectors and the quantities of end-use energy consumption. This section provides brief summaries of each of the modules.

Macroeconomic Activity Module

The Macroeconomic Activity Module (MAM) provides a set of macroeconomic drivers to the energy modules and receives energy-related indicators from the NEMS energy components as part of the macroeconomic feedback mechanism within NEMS. Key macroeconomic variables used in the energy modules include gross domestic product (GDP), disposable income, value of industrial shipments, new housing starts, sales of new LDVs, interest rates, and employment. Key energy indicators fed back to the MAM include aggregate energy prices and costs. The MAM uses the following models from IHS-Global Insight: Macroeconomic Model of the U.S. Economy, National Industry Model, and National Employment Model. In addition, EIA has constructed a Regional Economic and Industry Model to project regional economic drivers, and a Commercial Floorspace Model to project 13 floorspace types in 9 Census divisions. The accounting framework for industrial value of shipments uses the North American Industry Classification System (NAICS).

International Energy Module

The International Energy Module (IEM) uses assumptions of economic growth and expectations of future U.S. and world petroleum liquids production and consumption, by year, to project the interaction of U.S. and international liquids markets. The IEM computes world oil prices, provides a world crude-like liquids supply curve, generates a worldwide oil supply/demand balance for each year of the projection period, and computes initial estimates of crude oil and light and heavy petroleum product imports to the United States by PADD regions. The supply-curve calculations are based on historical market data and a world oil supply/demand balance, which is developed from reduced-form models of international liquids supply and demand, current investment trends in exploration and development, and long-term resource economics. The oil production estimates include both conventional and unconventional supply recovery technologies.

In interacting with the rest of NEMS, the IEM changes the world oil price—which is defined as the price of foreign light, low sulfur crude oil delivered to Cushing, Oklahoma (in Petroleum Administration for Defense District 2)—in response to changes in expected production and consumption of crude oil and product liquids in the United States.

Residential and Commercial Demand Modules

The Residential Demand Module projects energy consumption in the residential sector by housing type and end use, based on delivered energy prices, the menu of equipment available, the availability and cost of renewable sources of energy, and housing starts. The Commercial Demand Module projects energy consumption in the commercial sector by building type and non-building uses of energy and by category of end use, based on delivered prices of energy, availability of renewable sources of energy, and macroeconomic variables representing interest rates and floorspace construction.

Both modules estimate the equipment stock for the major end-use services, incorporating assessments of advanced technologies, including representations of renewable energy technologies, and the effects of both building shell and appliance standards, including the 2009 and 2010 consensus agreements reached between manufacturers and environmental interest groups. The Commercial Demand Module incorporates combined heat and power (CHP) technology. The modules also include projections of distributed generation (DG). Both modules incorporate changes to "normal" heating and cooling degree-days by Census division, based on a 10-year average and on State-level population projections. The Residential Demand Module projects an increase in the average square footage of both new construction and existing structures, based on trends in new construction and remodeling.

Industrial Demand Module

The Industrial Demand Module (IDM) projects the consumption of energy for heat and power, feedstocks, and raw materials in each of 21 industries, subject to the delivered prices of energy and the values of macroeconomic variables representing employment and the value of shipments for each industry. As noted in the description of the MAM, the value of shipments is based on NAICS. The industries are classified into three groups—energy-intensive manufacturing, non-energy-intensive manufacturing, and nonmanufacturing. Of the eight energy-intensive industries, seven are modeled in the IDM, with energy-consuming components for boiler/steam/cogeneration, buildings, and process/assembly use of energy. The use of energy for petroleum refining is modeled in the Petroleum Market Module (PMM), as described below, and the projected consumption is included in the industrial totals.

A generalized representation of cogeneration and a recycling component also are included. A new economic calculation for CHP systems was implemented for *AEO2011*. The evaluation of CHP systems now uses a discount rate, which depends on the 10-year Treasury bill rate plus a risk premium, replacing the previous calculation that used simple payback. Also, the base year of the IDM was updated to 2006 in keeping with an update to EIA's 2006 Manufacturing Energy Consumption Survey.

Transportation Demand Module

The Transportation Demand Module projects consumption of fuels in the transportation sector, including petroleum products, electricity, methanol, ethanol, compressed natural gas, and hydrogen, by transportation mode, vehicle vintage, and size class, subject to delivered prices of energy fuels and macroeconomic variables representing disposable personal income, GDP, population, interest rates, and industrial shipments. Fleet vehicles are represented separately to allow analysis of other legislation and legislative proposals specific to those market segments. The Transportation Demand Module also includes a component to assess the penetration of alternative-fuel vehicles. The Energy Policy Act of 2005 (EPACT2005) and EIEA2008 are reflected in the assessment of impacts of tax credits on the purchase of hybrid gas-electric, alternative-fuel, and fuel-cell vehicles. Representations of corporate average fuel economy (CAFE) standards and of biofuel consumption in the module reflect standards enacted by the National Highway Traffic Safety Administration (NHTSA) and EPA, and provisions in EISA2007.

The air transportation component of the Transportation Demand Module explicitly represents air travel in domestic and foreign markets and includes the industry practice of parking aircraft in both domestic and international markets to reduce operating costs, as well as the movement of aging aircraft from passenger to cargo markets. For passenger travel and air freight shipments, the module represents regional fuel use in regional, narrow-body, and wide-body aircraft. An infrastructure constraint, which is also modeled, can potentially limit overall growth in passenger and freight air travel to levels commensurate with industry-projected infrastructure expansion and capacity growth.

Electricity Market Module

There are three primary submodules of the Electricity Market Module—capacity planning, fuel dispatching, and finance and pricing. The capacity expansion submodule uses the stock of existing generation capacity; the menu, cost, and performance of future generation capacity; expected fuel prices; expected financial parameters; expected electricity demand; and expected environmental regulations to project the optimal mix of new generation capacity that should be added in future years. The fuel dispatching submodule uses the existing stock of generation equipment types, their operation and maintenance costs and performance, fuel prices to the electricity sector, electricity demand, and all applicable environmental regulations to determine the least-cost way to meet that demand. The submodule also determines transmission and pricing of electricity. The finance and pricing submodule uses capital costs, fuel costs, macroeconomic parameters, environmental regulations, and load shapes to estimate generation costs for each technology.

All specifically identified options promulgated by the EPA for compliance with the Clean Air Act Amendments of 1990 (CAAA90) are explicitly represented in the capacity expansion and dispatch decisions; those that have not been promulgated (e.g., fine particulate proposals) are not incorporated. All financial incentives for power generation expansion and dispatch specifically identified in EPACT2005 have been implemented. Several States, primarily in the Northeast, have recently enacted air emission regulations for CO2 that affect the electricity generation sector, and those regulations are represented in AEO2011. The AEO2011 Reference case reflects the temporary reinstatement of the NOx and SO2 cap-and-trade programs included in CAIR due to the ruling issued by the United States Court of Appeals for the District of Columbia on December 23, 2008. State regulations on mercury also are reflected in *AEO2011*.

Although currently there is no Federal legislation in place that restricts greenhouse gas (GHG) emissions, regulators and the investment community have continued to push energy companies to invest in technologies that are less GHG-intensive. The trend is captured in the AEO2011 Reference case through a 3-percentage-point increase in the cost of capital when evaluating investments in new coal-fired power plants, new coal-to-liquids (CTL), and coal and biomass-to-liquids (CBTL) plants without carbon capture and storage (CCS).

Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships among the various sources of supply—onshore, offshore, and Alaska—by all production techniques, including natural gas recovery from coalbeds and low-permeability formations of sandstone and shale. The framework analyzes cash flow and profitability to compute investment and drilling for each of the supply sources, based on the prices for crude oil and natural gas, the domestic recoverable resource base, and the state of technology. Oil and natural gas production activities are modeled for 12 supply regions, including 6 onshore, 3 offshore, and 3 Alaskan regions.

The Onshore Lower 48 Oil and Gas Supply Submodule evaluates the economics of future exploration and development projects for crude oil and natural gas at the play level. Crude oil resources are divided into known plays and undiscovered plays, including highly fractured continuous zones, such as the Austin chalk and Bakken shale formations. Production potential from advanced secondary recovery techniques (such as infill drilling, horizontal continuity, and horizontal profile) and enhanced oil recovery (such as CO2 flooding, steam flooding, polymer flooding, and profile modification) are explicitly represented. Natural gas resources are divided into known producing plays, known developing plays, and undiscovered plays in high-permeability carbonate and sandstone, tight gas, shale gas, and coalbed methane.

Domestic crude oil production quantities are used as inputs to the PMM in NEMS for conversion and blending into refined petroleum products. Supply curves for natural gas are used as inputs to the Natural Gas Transmission and Distribution Module (NGTDM) for determining natural gas wellhead prices and domestic production.

Natural Gas Transmission and Distribution Module

The NGTDM represents the transmission, distribution, and pricing of natural gas, subject to end-use demand for natural gas and the availability of domestic natural gas and natural gas traded on the international market. The module tracks the flows of natural gas and determines the associated capacity expansion requirements in an aggregate pipeline network, connecting the domestic and foreign supply regions with 12 U.S. lower 48 demand regions. The 12 regions align with the 9 Census divisions, with three subdivided and Alaska handled separately. The flow of natural gas is determined for both a peak and off-peak period in the year, assuming a historically based seasonal distribution of natural gas demand. Key components of pipeline and distributor tariffs are included in separate pricing algorithms. An algorithm is included to project the addition of compressed natural gas retail fueling capability. The module also accounts for foreign sources of natural gas, including pipeline imports and exports to Canada and Mexico, as well as liquefied natural gas (LNG) imports and exports.

Petroleum Market Module

The PMM projects prices of petroleum products, crude oil and product import activity, and domestic refinery operations, subject to demand for petroleum products, availability and price of imported petroleum, and domestic production of crude oil, natural gas liquids, and biofuels—ethanol, biodiesel, biomass-to-liquids (BTL), CTL, and gas-to-liquids (GTL). Costs, performance, and first dates of commercial availability for the advanced alternative liquids technologies [3] are reviewed and updated annually.

The module represents refining activities in the five PADDs, as well as a less detailed representation of refining activities in the rest of the world. It models the costs of automotive fuels, such as conventional and reformulated gasoline, and includes production of biofuels for blending in gasoline and diesel. Fuel ethanol and biodiesel are included in the PMM, because they are commonly blended into petroleum products. The module allows ethanol blending into gasoline at 10 percent or less by volume (E10), 15 percent by volume (E15) in States that lack explicit language capping ethanol volume or oxygen content, and up to 85 percent by volume (E85) for use in flex-fuel vehicles.

The PMM includes representation of the Renewable Fuels Standard (RFS) included in EISA2007, which mandates the use of 36 billion gallons of renewable fuel by 2022. Both domestic and imported ethanol count toward the RFS. Domestic ethanol production is modeled for three feedstock categories: corn, cellulosic plant materials, and advanced feedstock materials. Corn-based ethanol plants are numerous (more than 180 are now in operation, with a total operating production capacity of more than 13 billion gallons annually), and they are based on a well-known technology that converts starch and sugar into ethanol. Ethanol from cellulosic sources is a new technology with only a few small pilot plants in operation.

Fuels produced by gasification and Fischer-Tropsch synthesis and through a pyrolysis process are also modeled in the PMM, based on their economics relative to competing feedstocks and products. The five processes modeled are CTL, GTL, BTL, CBTL, and pyrolysis.

Coal Market Module

The Coal Market Module (CMM) simulates mining, transportation, and pricing of coal, subject to end-use demand for coal differentiated by heat and sulfur content. U.S. coal production is represented in the CMM by 41 separate supply curves—differentiated by region, mine type, coal rank, and sulfur content. The coal supply curves respond to capacity utilization of mines, mining capacity, labor productivity, and factor input costs (mining equipment, mining labor, and fuel requirements). Projections of U.S. coal distribution are determined by minimizing the cost of coal supplied, given coal demands by region and sector, environmental restrictions, and accounting for minemouth prices, transportation costs, and coal supply contracts. Over the projection horizon, coal transportation costs in the CMM vary in response to changes in the cost of rail investments.

The CMM produces projections of U.S. steam and metallurgical coal exports and imports in the context of world coal trade, determining the pattern of world coal trade flows that minimizes production and transportation costs while meeting a specified set of regional world coal import demands, subject to constraints on export capacities and trade flows. The international coal market component of the module computes trade in 3 types of coal for 17 export regions and 20 import regions. U.S. coal production and distribution are computed for 14 supply regions and 16 demand regions.

Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules representing renewable resource supply and technology input information for central-station, grid-connected electricity generation technologies, including conventional hydroelectricity, biomass (dedicated biomass plants and co-firing in existing coal plants), geothermal, landfill gas, solar thermal electricity, solar photovoltaics (PV), and wind energy. The RFM contains renewable resource supply estimates representing the regional opportunities for renewable energy development. Investment tax credits (ITCs) for renewable fuels are incorporated, as currently enacted, including a permanent 10-percent ITC for business investment in solar energy (thermal nonpower uses as well as power uses) and geothermal power (available only to those projects not accepting the production tax credit [PTC] for geothermal power). In addition, the module reflects the increase in the ITC to 30 percent for solar energy systems installed before January 1, 2017, and the extension of the credit to individual homeowners under EIEA2008.

PTCs for wind, geothermal, landfill gas, and some types of hydroelectric and biomass-fueled plants also are represented. They provide a credit of up to 2.1 cents per kilowatthour for electricity produced in the first 10 years of plant operation. For *AEO2011*, new wind plants coming on line before January 1, 2013, are eligible to receive the PTC; other eligible plants must be in service before January 1, 2014. As part of the ARRA, plants eligible for the PTC may instead elect to receive a 30-percent ITC or an equivalent direct grant. *AEO2011* also accounts for new renewable energy capacity resulting from State renewable portfolio standard (RPS) programs, mandates, and goals, as described in *Assumptions to the Annual Energy Outlook 2011*.

Cases for the *Annual Energy Outlook 2011*

In preparing projections for the *AEO2011*, EIA evaluated a wide range of trends and issues that could have major implications for U.S. energy markets between now and 2035. Besides the Reference case, the *AEO2011* presents detailed results for six alternative cases that differ from each other due to fundamental assumptions concerning the domestic economy and world oil market conditions. These alternative cases include the following:

- Economic Growth - In the Reference case, real GDP grows at an average annual rate of 2.7 percent from 2009 through 2035, supported by a 2.0 percent per year growth in productivity in nonfarm business, a 1.0 percent per year growth in nonfarm employment, and population growth of 0.9 percent per year. In the High Economic Growth case, real GDP is projected to increase by 3.2 percent per year, with population growth of 1.2 percent per year and productivity and nonfarm employment growing at 2.4 percent and 1.4 percent per year, respectively. In the Low Economic Growth case, the average annual growth in GDP, population, productivity, and nonfarm employment is 2.1, 0.6, 1.6 and 0.7 percent per year, respectively.
- Price Cases - For purposes of the *AEO2011*, the world oil price is defined as the average price of light, low-sulfur crude oil delivered in Cushing, Oklahoma, and is similar to the price of light, sweet crude oil traded on the New York Mercantile Exchange. The historical record shows substantial variability in world oil prices, and there is arguably even more uncertainty about future prices in the long term. *AEO2011* considers four alternative oil price cases (Low Oil Price, Traditional Low Oil Price, High Oil Price, and Traditional High Oil Price) to allow an assessment of alternative views on the course of future oil prices. The Low Oil Price case and Traditional Low Oil Price case use the same price path, as do the High Oil Price case and Traditional High Oil Price. The Low and High Oil Price cases reflect a wide range of potential price paths, resulting from variation in demand for countries outside the Organisation for Economic Co-operation and Development (OECD) for liquid fuels due to different levels of economic growth. The Traditional Low and Traditional High Oil Price cases define the same wide range of potential price paths, but they also reflect different assumptions about decisions by members of the Organization of the Petroleum Exporting Countries (OPEC) regarding the preferred rate of oil production and about the future finding and development costs and accessibility of conventional oil resources outside the United States. Because the Low, Traditional Low, High, and Traditional High Oil Price cases are not fully integrated with a world economic model, the impact of world oil prices on international economies is not accounted for directly.

  - In the Reference case, real world oil prices rise from a low of $78 per barrel (2009 dollars) in 2010 to $95 per barrel in 2015, then increase more slowly to $125 per barrel in 2035. The Reference case represents EIA's current judgment regarding exploration and development costs and accessibility of oil resources outside the United States. It also assumes that OPEC producers will choose to maintain their share of the market and will schedule investments in incremental production capacity so that OPEC's conventional oil production will represent about 42 percent of the world's total liquids production.

  - In the Low Oil Price case, world crude oil prices are only $50 per barrel (2009 dollars) in 2035, compared with $125 per barrel in the Reference case. In the Low Oil Price case, the low price results from lower demand for liquid fuels in the non-OECD nations. Lower demand is derived from lower economic growth relative to the Reference case. In this case, GDP growth in the non-OECD is reduced by 1.5 percentage points in each projection year beginning in 2015 relative to Reference case. The OECD projections are only affected by the price impact.

  - In the Traditional Low Oil Price case, the OPEC countries increase their conventional oil production to obtain a 52-percent share of total world liquids production, and oil resources outside the U.S. are more accessible and/or less costly to produce (as a result of technology advances, more attractive fiscal regimes, or both) than in the Reference case. With these assumptions, conventional oil production outside the United States is higher in the Traditional Low Oil Price case than in the Reference case. Prices are the same as in the Low Oil Price case.

  - In the High Oil Price case, world oil prices reach about $200 per barrel (2009 dollars) in 2035. In the High Oil Price case, the high prices result from higher demand for liquid fuels in the non-OECD nations. Higher demand is measured by higher economic growth relative to the Reference case. In this case, GDP growth in the non-OECD region is raised by 1.0 percentage points relative to Reference case in each projection year, starting in 2015. The OECD projections are only affected by the price impact.

- In the Traditional High Oil Price case, OPEC countries are assumed to reduce their production from the current rate, sacrificing market share, and oil resources outside the United States are assumed to be less accessible and/or more costly to produce than in the Reference case. Prices are the same as in the High Oil Price case.

In addition to these cases, 49 additional alternative cases presented in Table 1.1 explore the impact of changing key assumptions on individual sectors. Many of the side cases were designed to examine the impacts of varying key assumptions for individual modules or a subset of the NEMS modules, and thus the full market consequences, such as the consumption or price impacts, are not captured. In a fully integrated run, the impacts would tend to narrow the range of the differences from the reference case. For example, the Best Available Technology case for the residential sector assumes that all future equipment purchases are made from a selection of the most efficient technologies available in a particular year. In a fully integrated NEMS run, the lower resulting fuel consumption would have the effect of lowering the market prices of those fuels with the concomitant impact increasing economic growth, thus stimulating some additional consumption. The results of single model or partially integrated cases should be considered the maximum range of the impacts that could occur with the assumptions defined for the case.

Table 1.1. Summary of *AEO2011* cases

Case name	Description	Integration Mode
Reference	Baseline economic growth (2.7 percent per year from 2009 through 2035), world oil price, and technology assumptions. World light, sweet crude oil prices rise to about $125 per barrel (2009 dollars) in 2035. Assumes RFS target to be met as soon as possible.	Fully integrated
Low Economic Growth	Real GDP grows at an average annual rate of 2.1 percent from 2009 to 2035. Other energy market assumptions are the same as in the Reference case.	Fully integrated
High Economic Growth	Real GDP grows at an average annual rate of 3.2 percent from 2009 to 2035. Other energy market assumptions are the same as in the Reference case.	Fully integrated
Low Oil Price (primary low price case)	Low prices result from low demand for liquid fuels in the non-OECD nations. Lower demand is measured by lower economic growth relative to the Reference case. In this case, GDP growth in the non-OPEC region is reduced by 1.5 percentage points in each projection year relative to Reference case assumptions from 2015 to 2035. World light, sweet crude oil prices fall to about $50 per barrel in 2035, compared with $125 per barrel in the Reference case (2009 dollars). Other assumptions are the same as in the Reference case.	Fully integrated
Traditional Low Oil Price	More optimistic assumptions for economic access to non-OPEC resources and OPEC production decisions than in the Reference case. Prices are the same as those used in the Low Oil Price case.	Fully integrated
High Oil Price (primary high price case)	High prices result from high demand for liquid fuels in the non-OECD nations. Higher demand is measured by higher economic growth relative to the Reference case. In this case, GDP growth in the non-OECD region is raised by 1.0 percentage points in each projection year relative to Reference case assumptions from 2015 to 2035. World light, sweet crude oil prices rise to about $200 per barrel (2009 dollars) in 2035. Other assumptions are the same as in the Reference case.	Fully integrated
Traditional High Oil Price	More pessimistic assumptions for economic access to non-OPEC resources and OPEC production decisions than in the Reference case. Prices are the same as those used in the High Oil Price case.	Fully integrated
No Sunset	Begins with the Reference case and assumes extension of all existing energy policies and legislation that contain sunset provisions, except those requiring additional funding (e.g., loan guarantee programs) and those that involve extensive regulatory analysis, such as CAFE improvements and periodic efficiency standard updates.	Fully integrated
Extended Policies	Begins with the No Sunset case but excludes extension of blender and other biofuel tax credits that were included in No Sunset case. Assumes expansion of the maximum industrial ITC and CHP credits and extension of the program. Includes assumptions of the "Expanded Standards and Codes case" described below. Assumes new LDV CAFE standards (to 46 miles per gallon by 2025) and tailpipe emissions proposal consistent with the CAFE 3% Growth case described below.	Fully integrated
Residential and commercial: Expanded Standards	Begins with Reference case assumptions for energy standards. Adds additional rounds of efficiency standards for currently covered products as well as new standards for products not yet covered. Efficiency levels assume improvement similar to those in ENERGY STAR or Federal Energy Management Plan (FEMP) guidelines.	Residential and commercial only
Residential and Commercial: Expanded Standards and Codes	Begins with Expanded Standards case and adds multiple rounds of national building codes by 2026.	Residential and commercial only
Residential: 2010 Technology	Future equipment purchases based on equipment available in 2009. New and existing building shell efficiencies fixed at 2009 levels.	With commercial
Residential: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Building shell efficiencies for new construction meet ENERGY STAR requirements after 2015. Consumers evaluate efficiency investments at a 7-percent real discount rate.	With commercial
Residential: Best Available Technology	Future equipment purchases and new building shells based on most efficient technologies available by fuel. Building shell efficiencies for new construction meet the criteria for most efficient components after 2010.	With commercial
Commercial: 2010 Technology	Future equipment purchases based on equipment available in 2010. Building shell efficiencies fixed at 2010 levels.	With residential

Table 1.1. Summary of *AEO2011* cases (cont.)

Case name	Description	Integration Mode
Commercial: High Technology	Earlier availability, lower costs, and higher efficiencies for more advanced equipment. Energy efficiency investments evaluated at a 7-percent real discount rate. Building shell efficiencies for new and existing buildings increase by 17.4 and 7.5 percent, respectively, from 2003 values by 2035.	With residential
Commercial: Best Available Technology	Future equipment purchases based on most efficient technologies available by fuel. Building shell efficiencies for new and existing buildings increase by 20.8 and 9.0 percent, respectively, from 2003 values by 2035.	With residential
Industrial 2010 Technology	Efficiencies of plant and equipment fixed at 2010 levels.	Standalone
Industrial High Technology	Earlier availability, lower costs, and higher efficiencies for more advanced quipment.	Standalone
Transportation: Low Technology	Advanced technologies are more costly and less efficient than in the Reference case.	Standalone
Transportation: High Technology	Advanced technologies are less costly and more efficient than in the Reference case.	Standalone
Transportation: CAFE 3% Growth	Implements a 3-percent annual increase in fuel economy standards for LDVs from 2017 to 2025, with CAFE standard reaching 46 miles per gallon in 2025. Standards are held constant after 2025.	Fully integrated
Transportation: CAFE 6% Growth	Implements a 6-percent annual increase in fuel economy standards for LDVs from 2017 to 2025, with CAFE standard reaching 59 miles per gallon in 2025. Standards are held constant after 2025.	Fully integrated
Transportation: Heavy-Duty Vehicle Fuel Economy Standards	Implements increased fuel economy standards for heavy-duty vehicles for model years 2014 through 2018. Standards are held constant after 2018.	Fully integrated
Electricity: Low Fossil Technology Cost	Capital and operating costs for all new fossil-fired generating technologies start 20 percent below the Reference case level and decline to 40 percent below the Reference case in 2035.	Fully integrated
Electricity: High Fossil Technology Cost	Costs for all new fossil-fired generating technologies do not improve due to learning from 2011 levels in the Reference case.	Fully integrated
Electricity: Low Nuclear Cost	Capital and operating costs for new nuclear capacity start 20 percent lower than in the Reference case and fall to 40 percent lower in 2035.	Fully integrated
Electricity High Nuclear Costs	Costs for new nuclear technology do not improve due to learning from 2011 levels in the Reference case.	Fully integrated
Electricity: Frozen Plant Capital Costs	Base overnight costs for all new electricity generating technologies are frozen at 2015 levels. Costs decline due to learning, but do not decline due to commodity price changes.	Fully integrated
Electricity: Decreasing Plant Capital Costs	Base overnight costs for all new electric generating technologies fall more rapidly than in the Reference case, starting 20 percent below the Reference case costs in 2011 and falling to 40 percent below in 2035.	Fully integrated
Electricity: Transport Rule Mercury MACT 5	Assumes that the Transport Rule limits SO2 and NOx emissions and requires use of a 90-percent mercury maximum achievable control technology (MACT). A 5-year capital recovery period is assumed for the retrofits.	Fully integrated
Electricity: Transport Rule Mercury MACT 20	Same environmental rules as above, but assuming a 20-year capital recovery period for retrofits.	Fully integrated
Electricity: Retrofit Required 5	Assumes that all coal-fired plants are required to install flue gas desulfurization (FGD) scrubbers by 2020 to comply with acid gas reduction requirements and that all plants install selective catalytic reduction (SCR) in order to meet future NOx and ozone requirements. Assumes a 5-year capital recovery period for retrofits.	Fully integrated

Table 1.1. Summary of *AEO2011* cases (cont.)

Case name	Description	Integration mode
Electricity; Retrofit Required 20	Same requirements on environmental controls as above, but assuming a 20-year capital recovery period for retrofits.	Fully Integrated
Electricity: Low Gas Price Retrofit Required 5	Same assumptions as the Retrofit Required 5 case, plus assumption of increased domestic shale gas availability and utilization rate as in the High Shale Estimated Ultimate Recovery (EUR) case described below.	Fully Integrated
Electricity: Low Gas Price Retrofit Required 20	Same assumptions as the Retrofit Required 20 case, plus assumption of increased domestic shale gas availability and utilization rate as in the High Shale EUR case described below.	Fully Integrated
Renewable Fuels: Low Renewable Technology Cost	Costs for new nonhydropower renewable generating technologies start 20 percent lower in 2011 and decline to 40 percent lower than Reference case levels in 2035. Capital costs of renewable liquid fuel technologies start 20 percent lower in 2011 and decline to approximately 40 percent lower than Reference case levels in 2035.	Fully Integrated
Renewable Fuels: High Renewable Technoloy Cost	Costs for new non-hydropower renewable generating technologies do not improve from 2011 levels over the projection. Capital costs of renewable liquid fuel technologies do not improve from 2011 levels over the projection.	Fully integrated
Oil and Gas: Slow Technology	Improvements in exploration and development costs, production rates, and success rates due to technological advancement are 50 percent lower than in the Reference case.	Fully integrated
Oil and Gas: Rapid Technology	Improvements in exploration and development costs, production rates, and success rates due to technological advancement are 50 percent higher than in the Reference case	Fully integrated
Oil and Gas: Reduced OCS Access	No lease sales occur in the Eastern Gulf of Mexico, Pacific, Atlantic, and Alaska Outer Continental Shelf (OCS) through 2035.	Fully integrated
Oil and Gas: High OCS Resource	Oil and natural gas resources in the Pacific, Eastern Gulf of Mexico, Atlantic, and Alaska OCS are assumed to be three times higher than in the Reference case.	Fully integrated
Oil and Gas: High OCS Costs	Costs for exploration and development of oil and natural gas resources in the OCS are assumed to be 30 percent higher than in the Reference case.	Fully integrated
Oil and Gas: Low Shale EUR	EUR per shale gas well is assumed to be 50 percent lower than in the Reference case.	Fully integrated
Oil and Gas: High Shale EUR	EUR per shale gas well is assumed to be 50 percent higher than in the Reference case.	Fully integrated
Oil and Gas: Low Shale Recovery	Estimated undeveloped technically recoverable shale gas resource base is 50 percent lower than in the Reference case, with recovery rate per well unchanged from the Reference case, resulting in fewer wells needed to fully recover the resource.	Fully integrated
Oil and Gas: High Shale Recovery	Estimated undeveloped technically recoverable shale gas resource base is 50 percent higher than in the Reference case, with recovery rate per well unchanged from the Reference case, resulting in more wells needed to fully recover the resource.	Fully integrated
Oill and Gas: Low E15 Penetration	Consumers and retailers adopt E15 at a minimal rate in States that do not prohibit E15 blends.	Fully integrated
Oil and Gas: High E15 Penetration	All States that currently limit or prohibit E15 remove the restrictions by 2015. Consumers and retailers adopt widespread E15 blending.	Fully integrated
Coal: Low Coal Cost	Regional productivity growth rates for coal mining are approximately 2.7 percent per year higher than in the Reference case, and coal mining wages, mine equipment, and coal transportation rates are between 22 and 25 percent lower by 2035 than in the Reference case.	Fully Integrated

Table 1.1. Summary of *AEO2011* cases (cont.)

Case name	Description	Integration mode
Coal: High Coal Cost	Regional productivity growth rates for coal mining are approximately 2.7 percent per year lower than in the Reference case, and coal mining wages, mine equipment, and coal transportation rates are between 25 and 28 percent by higher by 2035 than in the Reference case.	Fully Integrated
Integrated Low Technology	Combination of the Residential, Commercial, and Industrial 2010 Technology cases and the Electricity High Fossil Technology Cost, High Renewable Technology Cost, and High Nuclear Cost cases.	Fully Integrated
Integrated High Technology	Combination of the Residential, Commercial, Industrial, and Transportation High Technology cases and the Electricity Low Fossil Technology Cost, Low Renewable Technology Cost, and Low Nuclear Cost cases	Fully Integrated
No GHG Concern	No GHG emissions reduction policy is enacted, and market investment decisions are not altered in anticipation of such a policy	Fully Integrated
GHG Price Economywide	Applies a price for CO2 emissions throughout the economy. The CO2 price assumed starts at $25 per ton beginning in 2013 and increases to $75 per ton in 2035.	Fully integrated
Low EOR	The quantity of CO2 available for CO2-enhanced oil recovery (EOR) from industrial sources with high-purity CO2 emissions is reduced from the Reference case. All other assumptions are the same as the Reference case.	Fully integrated
Low EOR/GHG Price Economywide	Same as the Low EOR case but with the same carbon price as in the GHG Price Economywide case.	Fully integrated

Carbon dioxide emissions

Carbon dioxide emissions from energy use are dependent on the carbon content of the fossil fuel, the fraction of the fuel consumed in combustion, and the consumption of that fuel. The product of the carbon content at full combustion and the combustion fraction yields an adjusted carbon emission factor for each fossil fuel. The emissions factors are expressed in millions of metric tons of carbon dioxide emitted per quadrillion Btu of energy use, or equivalently, in kilograms of carbon dioxide per million Btu. The adjusted emissions factors are multiplied by the energy consumption of the fossil fuel to arrive at the carbon dioxide emissions projections.

For fuel uses of energy, all of the carbon is assumed to be oxidized, so the combustion fraction is equal to 1.0 (in keeping with a recent change in international conventions). Previously, a small fraction of the carbon content of the fuel was assumed to remain unoxidized. The carbon in nonfuel use of energy, such as for asphalt and petrochemical feedstocks, is assumed to be sequestered in the product and not released to the atmosphere. For energy categories that are mixes of fuel and nonfuel uses, the combustion fractions are based on the proportion of fuel use. In calculating carbon dioxide emissions for motor gasoline, the direct emissions from renewable blending stock (ethanol) is omitted. Similarly, direct emissions from biodiesel are omitted from reported carbon dioxide emissions.

Any carbon dioxide emitted by biogenic renewable sources, such as biomass and alcohols, is considered balanced by the carbon dioxide sequestration that occurred in its creation. Therefore, following convention, net emissions of carbon dioxide from biogenic renewable sources are assumed to be zero in reporting energy-related carbon dioxide emissions; however, to illustrate the potential for these emissions in the absence of any offsetting sequestration, as might occur under related land use change, the carbon dioxide emissions from biogenic fuel use are calculated and reported separately.

Table 1.2 presents the assumed carbon dioxide coefficients at full combustion, the combustion fractions, and the adjusted carbon dioxide emission factors used for *AEO2011*.

Table 1.2. Carbon dioxide emission factors
million metric tons carbon dioxide equivalent per quadrillion Btu

Fuel Type	Carbon Dioxide Coefficient at Full Combustion	Combustion Fraction	Adjusted Emission Factor
Petroleum			
Motor Gasoline (net of ethanol)	70.88	1.0000	70.88
Liquefied Petroleum Gas			
Used as Fuel	62.97	1.0000	62.97
Used as Feedstock	61.27	0.2000	12.25
Jet Fuel	70.88	1.0000	70.88
Distillate Fuel (net of biodiesel)	73.15	1.0000	73.15
Residual Fuel	78.80	1.0000	78.80
Asphalt and Road Oil	75.61	0.0000	0.00
Lubricants	74.21	0.5000	37.11
Petrochemical Feedstocks	71.02	0.3533	25.09
Kerosene	72.31	1.0000	72.31
Petroleum Coke	102.12	0.9014	92.05
Petroleum Still Gas	64.20	1.0000	64.20
Other Industrial	74.54	1.0000	74.54
Coal			
Residential and Commercial	95.35	1.0000	95.35
Metallurgical	93.71	1.0000	93.71
Coke	114.14	1.0000	114.14
Industrial Other	93.88	1.0000	93.98
Electric Utility[1]	95.52	1.0000	95.52
Natural Gas			
Used as Fuel	53.06	1.0000	53.06
Used as Feedstocks	53.06	0.5270	27.96
Biogenic Energy Sources			
Biomass	88.45	1.0000	88.45
Biogenic Waste	90.65	1.0000	90.65
Biofuels Heats and Coproducts	88.45	1.0000	88.45
Ethanol	65.88	1.0000	65.88
Biodiesel	73.88	1.0000	73.88
Liquids from Biomass	73.15	1.0000	73.15
Green Liquids	73.15	1.0000	73.15

[1]Emission factors for coal used for electricity generation are specified by coal supply region and types of coal, so the average carbon dioxide content for coal varies throughout the projection. The 2009 average is 95.52.
Source: U.S. Energy Information Administration, Emissions of Greenhouse Gases in the United States 2009, DOE/EIA-0573(2009), (Washington, DC, February 2010).

Notes and sources

[1] Energy Information Administration, *Annual Energy Outlook 2011* (*AEO2011*), DOE/EIA-0383(2011), (Washington, DC, April 2011).

[2] NEMS documentation reports are available on the EIA Homepage (http://www.eia.gov/analysis/model-documentation.cfm).

[3] Alternative liquids technologies include all biofuel technologies plus CTL and GTL.

Macroeconomic Activity Module

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The Macroeconomic Activity Module (MAM) represents the interaction between the U.S. economy as a whole and energy markets. The rate of growth of the economy, measured by the growth in gross domestic product (GDP) is a key determinant of the growth in demand for energy. Associated economic factors, such as interest rates and disposable income, strongly influence various elements of the supply and demand for energy. At the same time, reactions to energy markets by the aggregate economy, such as a slowdown in economic growth resulting from increasing energy prices, are also reflected in this module. A detailed description of the MAM is provided in the EIA publication, Model Documentation Report: Macroeconomic Activity Module (MAM) of the National Energy Modeling System, DOE/EIA-M065(2011), (Washington, DC, June 2011).

Key assumptions

The output of the U.S. economy, measured by GDP, is expected to increase by 2.7 percent between 2009 and 2035 in the Reference case. Two key factors help explain the growth in GDP: the growth rate of nonfarm employment and the rate of productivity change associated with employment. As Table 2.1 indicates, real GDP growth slows during the first three years of the forecast, reflecting a slower near term recovery from the 2008 recession. Over the next ten years the economy recovers, and then returns to its long-run growth path. In the Reference case, real GDP grows by 2.4 percent for the first two years, and then attains 2.9 percent growth for the recovery period and 2.6 percent growth for the final fifteen years. Both the high and low macroeconomic growth cases show similar patterns of early lower growth, recovery and settling back into their respective long-run growth trends. In the near term from 2009 through 2011, the growth in nonfarm employment is low at 0.9 percent compared with 2.4 percent in the second half of the 1990s, while the economy is expected to experience productivity growth of 2.1 percent. Over the projection period, nonfarm employment is expected to grow by 1.0 percent per year. Nonfarm employment, a measure of demand for nonfarm labor, is generally more volatile than the labor force, a measure of labor supply. The latter depends upon the projection of population and labor force participation rate. The Census Bureau's middle series population projection is used as a basis for population growth for the *AEO2011*. Total population is expected to grow by 0.9 percent per year between 2009 and 2035, and the share of population over 65 is expected to increase over time. However, the share of the labor force in the population over 65 is also projected to increase in the projection period.

To achieve the Reference case's long-run 2.7 percent economic growth, there is an anticipated steady growth in labor productivity. The improvement in labor productivity reflects the positive effects of a growing capital stock as well as technological change over time. Nonfarm labor productivity is expected to remain between 2.0 and 2.1 percent for the remainder of the projection period from 2009 through 2035. Business fixed investment as a share of nominal GDP is expected to grow over the last 10 years of the projection. The resulting growth in the capital stock and the technology base of that capital stock helps to sustain productivity growth of 2.0 percent from the 2009 to 2035.

Table 2.1. Growth in gross domestic product, nonfarm employment and productivity

Assumptions	2009-2011	2011-2020	2020-2035	2009-2035
Real GDP (Billion Chain-Weighted $2005)				
High Growth	2.4%	3.6%	3.1%	3.2%
Reference	2.4%	2.9%	2.6%	2.7%
Low Growth	2.4%	2.1%	2.1%	2.1%
Nonfarm Employment				
High Growth	0.9%	2.0%	1.1%	1.4%
Reference	0.9%	1.2%	0.9%	1.0%
Low Growth	0.9%	0.4%	0.9%	0.7%
Productivity				
High Growth	2.1%	2.2%	2.5%	2.4%
Reference	2.1%	1.7%	2.1%	2.0%
Low Growth	2.1%	1.3%	1.6%	1.6%

Source: U.S. Energy Information Administration, *AEO2010* National Energy Modeling system runs: AEO2011.d020911A, LM2010.d020911A, and HM2010.d020911A.

To reflect the uncertainty in projection of U.S. economic growth, the *AEO2011* uses High and Low Economic Growth cases along with the Reference case to project the possible impacts on energy markets. The High Economic Growth case incorporates higher population, labor force and productivity growth rates than the Reference case. Due to the higher productivity gains, inflation and interest rates are lower compared to the Reference case. Investment, disposable income, and industrial production are increased. Economic output is projected to increase by 3.2 percent per year between 2009 and 2035. The Low Economic Growth case assumes lower population, labor force, and productivity gains, with resulting higher prices and interest rates and lower industrial output growth. In the Low Economic Growth case, economic output is expected to increase by 2.1 percent per year over the projection horizon.

International Energy Module

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The NEMS International Energy Module (IEM) simulates the interaction between U.S. and global petroleum markets. It uses assumptions of economic growth and expectations of future U.S. and world crude-like liquids production and consumption to estimate the effects of changes in U.S. liquid fuels markets on the international petroleum market. For each year of the forecast, the NEMS IEM computes world oil prices, provides a supply curve of world crude-like liquids, generates a worldwide oil supply-demand balance with regional detail, and computes quantities of crude oil and light and heavy petroleum products imported into the United States by export region.

Changes in the world oil price (WOP), which is defined as the price of light, low sulfur crude oil delivered to Cushing, Oklahoma in PADD2, are computed in response to:

1. The difference between projected U.S. total crude-like liquids production and the expected U.S. total crude-like liquids production at the current WOP (estimated using the current WOP and the exogenous U.S. total crude-like liquids supply curve for each year).

and

2. The difference between projected U.S. total crude-like liquids consumption and the expected U.S. total crude-like liquids consumption at the current WOP (estimated using the current WOP and the exogenous U.S. total crude-like liquids demand curve).

Key assumptions

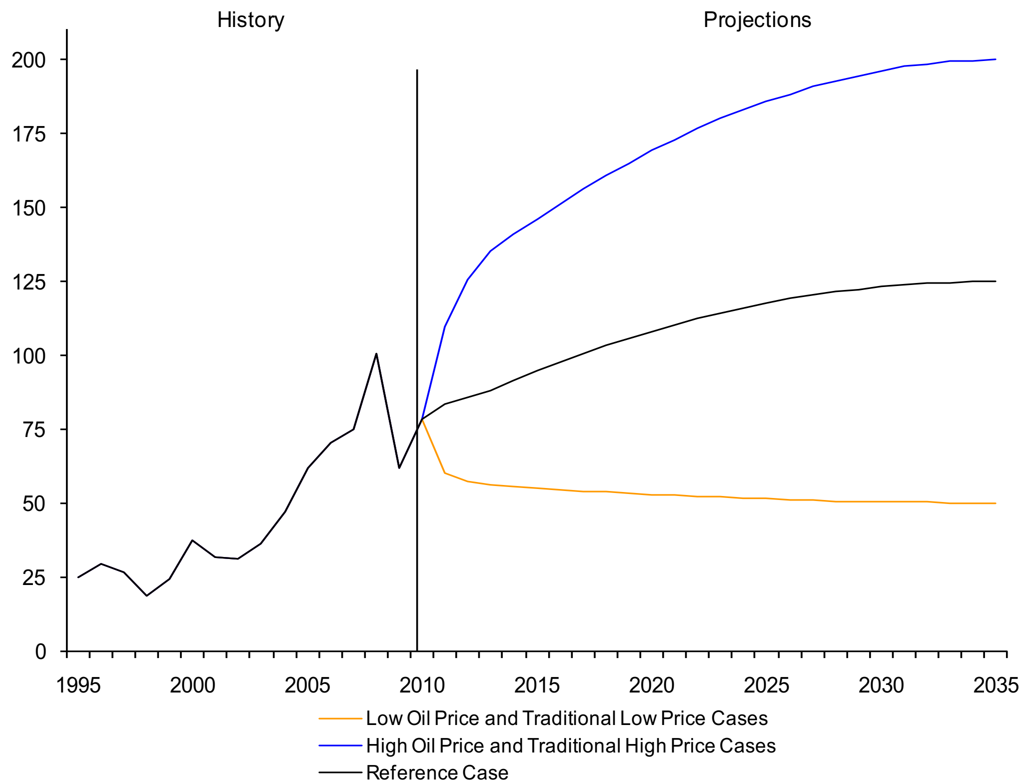
The level of oil production by OPEC is a key factor influencing the world oil price projections incorporated into *AEO2011*. Non-OPEC production, worldwide regional economic growth rates and the associated regional demand for oil are additional factors affecting the world oil price.

For the low, reference, and high oil price cases, the world oil price reaches $50, $125 and $200 per barrel in 2035, respectively, in 2009 dollars. The Reference case assumes that OPEC producers will continue to demonstrate a disciplined production approach. The traditional low oil price case reflects a market where all oil production becomes more competitive and plentiful. For the low price case (LNO), low prices result from low demand for liquid fuels in the non-OECD nations. Lower demand is measured by lower economic growth relative to the Reference case. In this case, GDP growth in the non-OECD is reduced by 1.5 percentage points in each projection year from 2015 on relative to Reference case assumptions. The traditional high oil price cases could result from a more cohesive and market-assertive OPEC that reduces overall production volumes while resource rich non-OPEC producers restrict economic access to their oil reserves. For the high price case (HNO), high prices result from high demand for liquid fuels in the non-OECD nations. Higher demand is measured by higher economic growth relative to the Reference case. In this case, GDP growth in the non-OECD is raised by 1.0 percentage point in each projection year from 2015 relative to Reference case assumptions. The five price scenarios are shown in Figure 2.

OPEC oil production in the Reference case is assumed to increase throughout the projection (Figure 3), at a rate that enables the organization to maintain an approximately constant market share over the projection period. OPEC is assumed to be an important source of additional production because its member nations hold a major portion of the world's total reserves—exceeding 950 billion barrels, about 70 percent of the world's estimated total, at the beginning of 2010.[1] Despite investment from foreign sources, Iraq's oil production is not assumed to maintain steady growth until after 2015 as infrastructure limitations as well as security and legislative issues are assumed to slow development for the next five years.

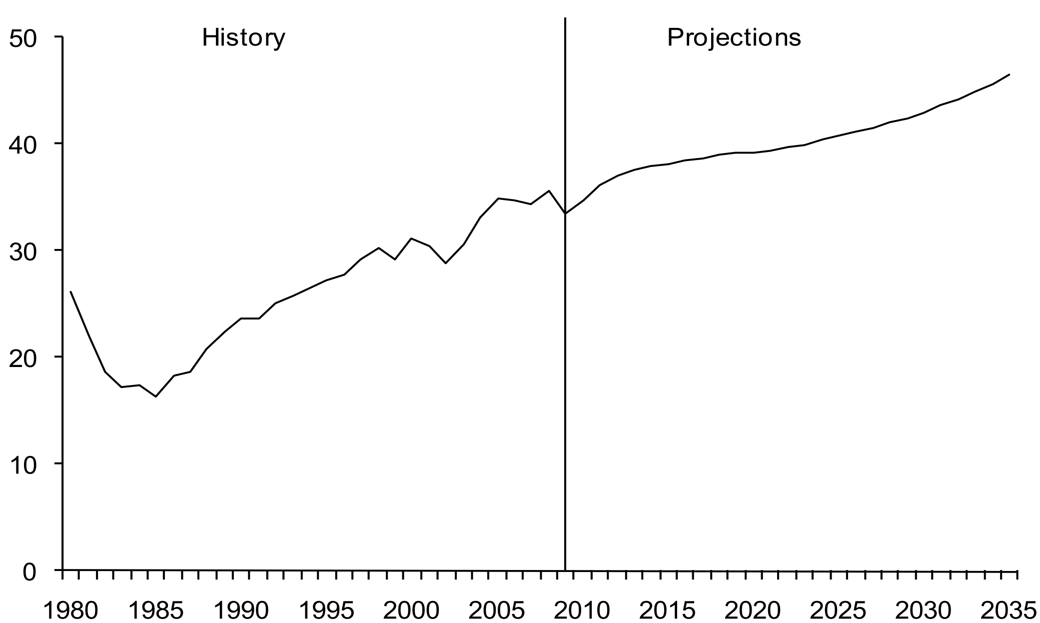
Non-U.S., non-OPEC oil production projections in the *AEO2011* are developed in two stages. Projections of liquids production before 2015 are based largely on a project-by-project assessment of major fields, including volumes and expected schedules, with consideration given to the decline rates of active projects, planned exploration and development activity, and country-specific geopolitical situations and fiscal regimes. Incremental production estimates from existing and new fields after 2015 are estimated based on country specific consideration of economics and ultimate technically recoverable resource estimates. The non-OPEC production path for the Reference case is shown in Figure 4.

Figure 2. World oil prices in five cases, 1995-2035
2008 dollars per barrel



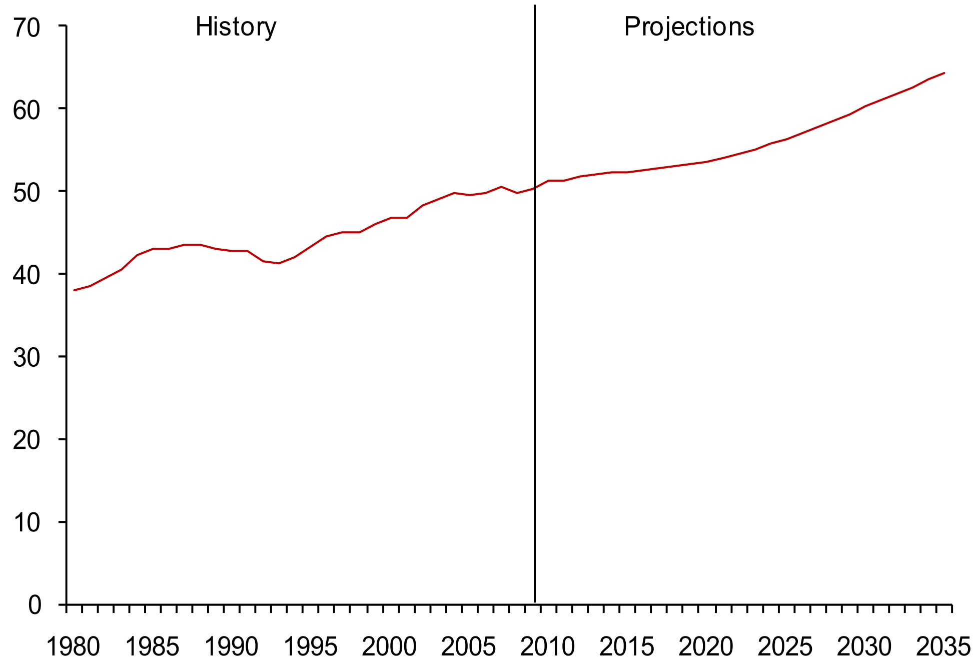
Source: U.S. Energy Information Administration. *AEO2011*, National Energy Modeling System runs REF2011.D020911A, HP2011hno.D020911A LP2011/lno.D020911A, HP2011mno.D020911A, and LP2011mno.D020911A.

Figure 3. OPEC total liquids production in the Reference case, 1995-2035
million barrels per day



OPEC = Organization of Petroleum Exporting Countries.
Source: U.S. Energy Information Administration. *AEO2011* National Energy Modeling Sysytem run REF2011.D020911A.

Figure 4 Non-OPEC total liquids production in the Reference case, 1995-2035
million barrels per day



OPEC = Organization of Petroleum Exporting Countries.
Source: U.S. Energy Information Administion. *AEO2011* National Energiy Modeling System run REF2011.D020911A.

The non-U.S. oil production projections in the *AEO2011* are limited by country-level assumptions regarding technically recoverable oil resources. Inputs to these resource estimates include the USGS World Petroleum Assessment of 2000 and oil reserves published in the Oil and Gas Journal by PennWell Publishing Company, a summary of which is shown in Table 3.1.

The Reference case growth rates for GDP for various regions in the world are shown in Table 3.2. Except for the United States, the GDP growth rate assumptions for non U.S. country/regions are taken from HIS Global Insight, Inc., Global detailed forecast (November 23, 2009).

The values for growth in total liquids demand in the International Energy Module, which depend upon the oil price levels as well as GDP growth rates, are shown in Table 3.3 for the Reference case by regions.

Table 3.1. Worldwide oil reserves as of January 1, 2010
billion barrels

Region	Proved Oil Reserves
Western Hemisphere	329.4
Western Europe	12.2
Asia-Pacific	40.1
Eastern Europe and Former Soviet Union (F.S.U.)	100.0
Middle East	753.4
Africa	119.1
Total World	1,354.2
Total OPEC	951.3

Source: Pennwell Corporation, Oil and Gas Journal, Vol 106. 48 (Dec. 21, 2009).

Table 3.2. Average annual real gross domestic product rates, 2007-2035
2005 purchasing power parity weights and prices

Region	Average Annual Percentage Change
OECD	2.01%
OECD Americas	2.52%
OECD Europe	1.68%
OECD Asia	1.42%
Non-OECD	4.39%
Non-OECD Europe and Eurasia	2.69%
Non-OECD Asia	5.21%
Middle East	3.73%
Africa	3.58%
Central and South America	3.41%
Total World	3.21%

Source: U.S. Energy Information Administration, National Energy Modeling System run REF2011.D020911A.

Table 3.3. Average annual growth rates for total liquids demand in the Reference case, 2007-2035
billion barrels

Region	Oil Demand Growth
OECD	-0.06%
OECD Americas	0.24%
OECD Europe	-0.60%
OECD Asia	-0.09%
Non-OECD	1.92%
Non-OECD Europe and Eurasia	0.42%
Non-OECD Asia	2.62%
Middle East	1.96%
Africa	1.27%
Central and South America	1.10%
Total World	0.92%

Source: U.S. Energy Information Administration, National Energy Modeling System run REF2011.D020911A; and World Energy Projection system Plus (2010), run AEO2011-STEOCLB2-101310B.

Notes and sources

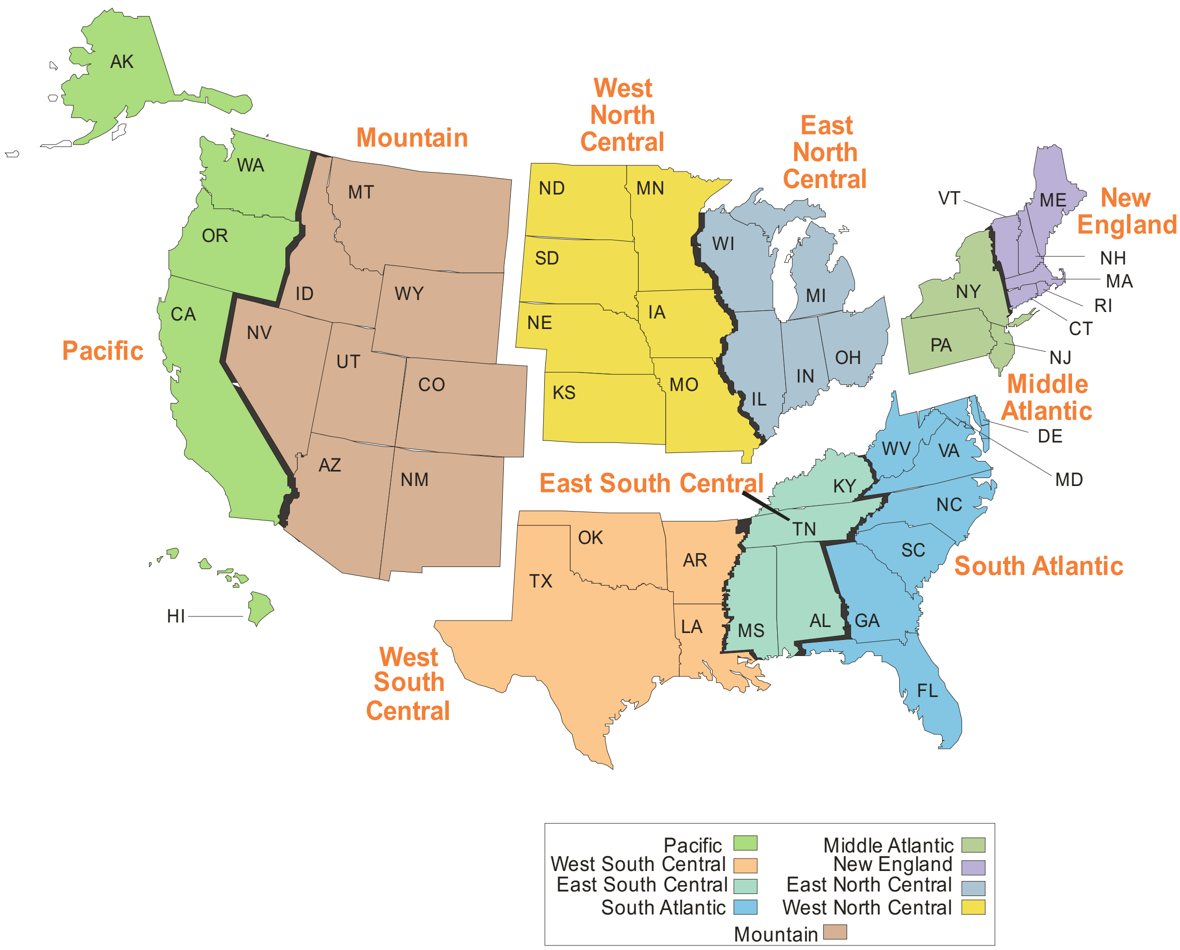
[1] PennWell Corporation, Oil and Gas Journal, Vol. 107.47 (December 21, 2009).

Residential Demand Module

The NEMS Residential Demand Module projects future residential sector energy requirements based on projections of the number of households and the stock, efficiency, and intensity of energy-consuming equipment. The Residential Demand Module projections begin with a base year estimate of the housing stock, the types and numbers of energy-consuming appliances servicing the stock, and the "unit energy consumption" by appliance (or UEC— in million Btu per household per year). The projection process adds new housing units to the stock, determines the equipment installed in new units, retires existing housing units, and retires and replaces appliances. The primary exogenous drivers for the module are housing starts by type (single-family, multifamily and mobile homes) and by Census Division and prices for each energy source for each of the nine Census Divisions (see Figure 5).

The Residential Demand Module also requires projections of available equipment and their installed costs over the projection horizon. Over time, equipment efficiency tends to increase because of general technological advances and also because of Federal and/or state efficiency standards. As energy prices and available equipment change over the projection horizon, the module includes projected changes to the type and efficiency of equipment purchased as well as projected changes in the usage intensity of the equipment stock.

Figure 5. United States Census Divisions



Source: U.S. Energy Information Administration, Office of Energy Analysis.

per household is projected for other electric and nonelectric appliances. The module's output includes number of households, equipment stock, average equipment efficiencies, and energy consumed by service, fuel, and geographic location. The fuels represented are distillate fuel oil, liquefied petroleum gas, natural gas, kerosene, electricity, wood, coal, geothermal, and solar energy.

One of the implicit assumptions embodied in the Residential Demand Module is that, through 2035, there will be no radical changes in technology or consumer behavior. With the exception of efficiency levels described in consensus agreements among equipment manufacturers and efficiency advocates, no new regulations of efficiency beyond those currently embodied in law or new government programs fostering efficiency improvements are assumed. Technologies which have not gained widespread acceptance today will generally not achieve significant penetration by 2035. Currently available technologies will evolve in both efficiency and cost. In general, at the same efficiency level, future technologies will be less expensive, in real dollar terms, than those available today. When choosing new or replacement technologies, consumers will behave similarly to the way they now behave. The intensity of end-uses will change moderately in response to price changes. Electric end uses will continue to expand, but at a decreasing rate. [1]

Key assumptions

Housing stock submodule

An important determinant of future energy consumption is the projected number of households. Base year estimates for 2005 are derived from the Energy Information Administration's (EIA) Residential Energy Consumption Survey (RECS) (Table 4.1). The projection for occupied households is done separately for each Census Division. It is based on the combination of the previous year's surving stock with projected housing starts provided by the NEMS Macroeconomic Activity Module. The Housing Stock Submodule assumes a constant survival rate (the percentage of households which are present in the current projection year, which were also present in the preceding year) for each type of housing unit; 99.6 percent for single-family units, 99.9 percent for multifamily units, and 97.6 percent for mobile home units.

Projected fuel consumption is dependent not only on the projected number of housing units, but also on the type and geographic distribution of the houses. The intensity of space heating energy use varies greatly across the various climate zones in the United States. Also, fuel prevalence varies across the country—oil (distillate) is more frequently used as a heating fuel in the New England and Middle Atlantic Census Divisions than in the rest of the country, while natural gas dominates in the Midwest. An example of differences by housing type is the more prevalent use of liquefied petroleum gas in mobile homes relative to other housing types.

Table 4.1. 2005 Households

Census	Single-Family Units	Multifamily Units	Mobile Homes	Total Units
New England	3,382,964	1,899,961	173,072	5,465,996
Mid Atlantic	10,077,231	4,794,686	254,610	15,116,527
East North Central	14,091,216	3,233,929	424,271	17,749,416
West North Central	6,107,582	1,406,214	340,759	7,854,555
South Atlantic	14,823,660	4,910,592	1,962,563	21,696,715
East South Central	5,438,660	729,591	724,503	6,892,754
West South Central	8,892,255	2,120,675	1,109,901	12,122,831
Mountain	5,680,398	951,482	922,976	7,554,856
Pacific	11,150,078	4,456,348	1,030,541	16,636,967
United States	79,653,923	24,493,498	6,943,196	111,090,617

Source: U.S. Department of Energy, Energy Information Administration, 2005 Residential Energy Consumption Survey.

Technology Choice Submodule

The key inputs for the Technology Choice Submodule are fuel prices by Census Division and characteristics of available equipment (installed cost, maintenance cost, efficiency, and equipment life). The Integrating Module of NEMS estimates fuel prices through an equillibrium simulation that balances supply and demand and passes the prices to the Residential submodule. Prices combined with equipment UEC (a function of efficiency) determine the operating costs of equipment. Equipment characteristics are exogenous to the model and are modified to reflect both Federal standards and anticipated changes in the market place. Table 4.2 lists capital cost and efficiency for selected residential appliances for the years 2010 and 2020.

Table 4.2. Installed cost and efficiency ratings of selected equipment

Equipment Type	Relative Performance[1]	2010 Installed Cost ($2007)[2]	2010 Efficiency[3]	2020 Installed Cost ($2007)[2]	2020 Efficiency[3]	Approximate Hurdle Rate
	Minimum	$4,200	13.0	$4,800	14.0	
Electric Heat Pump	Best	$5,200	18.0	$7,700	19.0	25%
	Minimum	$1,900	0.80	$2,200	0.90	
Natural Gas Furnace[4]	Best	$1,890	0.96	$2,700	0.96	15%
	Minimum	$310	9.8	$370	11.0	
Rom Air Conditioner	Best	$900	12.0	$875	12.0	42%
	Minimum	$2,600	13.0	$3,000	14.0	
Central Air Conditioner	Best	$5,500	23.0	$5,750	23.0	25%
	Minimum	$600	510	$828	388	
Refrigerator 23.9 cubic ft in adjusted volume)	Best	$1,050	417	$1,320	363	10%
	Minimum	$400	0.90	$500	0.95	
Electric Water Heater	Best	$1,190	2.4	$1,700	2.4	50%
Solar Water Heater[5]	N/A	$3,500	N/A	$4,000	N/A	30%

[1]Minimum performance refers to the lowest efficiency equipment available. Best refers to the highest efficiency equipment available.
[2]Installed costs are given in 2007 dollars in the original source document.
[3]Efficiency measurements vary by equipment type. Electric heat pumps and central air conditioners are rated for cooling performance using the Seasonal Energy Efficiency Ratio (SEER); natural gas furnaces are based on Annual Fuel Utilization Efficiency (AFUE); room air conditioners are based on Energy Efficiency Ratio (EER); refrigerators are based on kilowatt-hours per year; and water heaters are based on Energy Factor (delivered Btu divided by input Btu).
[4]Values are for Northern regions of U.S.
[5]Values are for Southern regions of U.S.
Source: EIA Technology Forecast Updates, (Navigant Consulting , 2007).

Table 4.3 provides the cost and performance parameters for representative distributed generation technologies. The *AEO2011* model also incorporates endogenous "learning" for the residential distributed generation technologies, allowing for declining technology costs as shipments increase. For fuel cell and photovoltaic systems, learning parameter assumptions for the *AEO2011* Reference case result in a 13 percent reduction in capital costs each time the number of units shipped to the buildings sectors (residential and commercial) doubles. Capital costs for small wind, a relatively mature technology, only decline 3 percent with each doubling of shipments.

The Residential Demand Module projects equipment purchases based on a nested choice methodology. The first stage of the choice methodology determines the fuel and technology to be used. The equipment choices for cooling, water heating, and cooking are linked to the space heating choice for new construction. Technology and fuel choice for replacement equipment uses a nested methodology similar to that for new construction, but includes (in addition to the capital and installation costs of the equipment) explicit costs for fuel or technology switching (e.g., costs for installing gas lines if switching from electricity or oil to gas, or costs for adding ductwork if switching from electric resistance heat to central heating types). Also, for replacements, there is no linking of fuel choice for water heating and cooking as is done for new construction. Technology switching upon replacement is allowed for space heating, air conditioning, water heating, cooking and clothes drying.

Once the fuel and technology choice for a particular end use is determined, the second stage of the choice methodology determines efficiency. In any given year, there are several available prototypes of varying efficiency (minimum standard, some intermediate levels, and highest efficiency). Efficiency choice is based on a functional form and coefficients which give greater or lesser importance to the installed capital cost (first cost) versus the operating cost. Generally, within a technology class, the higher the first cost, the lower the operating cost. For new construction, efficiency choices are made based on the costs of both the heating and cooling equipment and the building shell characteristics.

The parameters for the second stage efficiency choice are calibrated to the most recently available shipment data for the major residential appliances. Shipment efficiency data are obtained from industry associations which monitor shipments such as the Association of Home Appliance Manufacturers. Because of this calibration procedure, the model allows the relative importance of first cost versus operating cost to vary by general technology and fuel type (e.g. natural gas furnance, electric heat pump, electric central air conditioner, etc.). Once the model is calibrated, it is possible to obtain calculations for the apparent discount rates based on the relative weight given to the operating cost savings versus the weight given to the higher initial cost of more efficient equipment.

Hurdle rates in excess of 30 percent are common in the Residential Demand Module. The prevalence of such high apparent hurdle rates by consumers has led to the notion of the "efficiency gap" — that is, there are many investments that could be made that provide rates of return in excess of residential borrowing rates (10 to 20 percent for example). There are several studies which document instances of apparent high discount rates. [2] Once equipment efficiencies for a technology and fuel are determined, the installed efficiency for its entire stock is calculated.

Appliance stock submodule

The Appliance Stock Submodule is an accounting framework which tracks the quantity and average efficiency of equipment by end use, technology, and fuel. It separately tracks equipment requirements for new construction and existing housing units. For existing units, this module calculates the number of units which survive from previous years, allows certain end uses to further penetrate into the existing housing stock and calculates the total number of units required for replacement and further penetration. Air conditioning and clothes drying are the two major end uses not considered to be "fully penetrated."

Once a piece of equipment enters into the stock, an accounting of its remaining life begins. It is assumed that all appliances survive a minimum number of years, after which a fraction of appliances are removed from the stock. Between the minimum and maximum life expectancy, all appliances retire based on a linear decay function. For example, if an appliance has a minimum life of 5 years and a maximum life of 15 years, one tenth of the units (1 divided by 15 minum 5) are retired in each of years 6 through 15. It is further assumed that, when a house is retired from the stock, all of the equipment contained in that house retires as well; i.e., there is no secondhand market for this equipment. The assumptions concerning equipment lives are in Table 4.4.

Table 4.3. Capital cost and performance parameters of selected residential distributed generation technologies

Technology Type	Year of Introduction	Average Generating Capacity (kW_{DC})	Electrical Efficiency	Combined Efficiency (Elec. + Thermal	Installed Capital Cost (2009 $ per kW_{DC})[1]	Service Life (Years)
Solar Photovoltaic						
	2010	3.5	0.150	N/A	$7,183	30
	2015	4.0	0.175	N/A	$5,336	30
	2025	5.0	0.197	N/A	$4,284	30
	2035	5.0	0.200	N/A	$4,048	30
Fuel Cell						
	2010	10	0.364	0.893	$14,837	20
	2015	10	0.429	0.859	$14,837	20
	2025	10	0.456	0.842	$14,837	20
	2035	10	0.479	0.828	$14,837	20
Wind						
	2010	2	0.13	N/A	$7,802	30
	2015	3	0.13	N/A	$6,983	30
	2025	3	0.13	N/A	$6,234	30
	2035	4	0.13	N/A	$5,903	30

[1]The original source documents presented solar photovoltaic costs in 2008 dollars, fuel cell and wind costs in 2010 dollars.
Source: Solar photovoltaic: Photovoltaic (PV) Cost and Performance Characteristics for Residential and Commercial Applications (ICF International, 2010). Fuel cell: Commercial and Industrial CHP Technology Cost and Performance Data Analysis for EIA (SENTECH Incorporated, 2010). Wind: The Cost and Performance of Distributed Wind Turbines, 2010-35 (ICF International, 2010).

Table 4.4. Minimum and maximum life expectancies of equipment

Equipment	Minimum Life	Maximum Life
Heat Pumps	7	21
Central Forced-Air Furnaces	10	25
Hydronic Space Heaters	20	30
Room Air Conditioners	8	16
Central Air Conditioners	7	21
Gas Water Heaters	4	14
Electric Water Heaters	5	22
Cooking Stoves	16	21
Clothes Dryers	11	20
Refrigerators	7	26
Freezers	11	31

Source: Lawrence Berkely Laboratory. Baseline Data for the Residential Sector and Development of a Residential Forecasting Database, May 1994, and analysis of RECS 2001 data.

Fuel consumption submodule

Energy consumption is calculated by multiplying the vintage equipment stocks by their respective UECs. The UECs include adjustments for the average efficiency of the stock vintages, short term price elasticity of demand and "rebound" effects on usage (see discussion below), the size of new construction relative to the existing stock, people per household, shell efficiency and weather effects (space heating and cooling). The various levels of aggregated consumption (consumption by fuel, by service, etc.) are derived from these detailed equipment-specific calculations.

Equipment efficiency

The average energy consumption of a particular technology is initially based on estimates derived from RECS 2005. Appliance efficiency is either derived from a long history of shipment data (e.g., the efficiency of conventional air-source heat pumps) or assumed based on engineering information concerning typical installed equipment (e.g., the efficiency of ground-source heat pumps). When the average efficiency is computed from shipment data, shipments going back as far as 20 to 30 years are combined with assumptions concerning equipment lifetimes. This allows for not only an average efficiency to be calculated, but also for equipment to be vintaged and retirements to be projected by vintage and efficiency, as older equipment tends to be lower in efficiency and also tends to get retired before newer, more efficient equipment. Once equipment is retired, the Appliance Stock and Technology Choice Modules determine the efficiency of the replacement equipment. It is often the case that the retired equipment is replaced by substantially more efficient equipment.

As the stock efficiency changes over the simulation interval, energy consumption decreases in inverse proportion to efficiency. Also, as efficiency increases, the efficiency rebound effect (discussed below) will offset some of the reductions in energy consumption by increased demand for the end-use service. For example, if the stock average for electric heat pumps is now 10 percent more efficient than in 2005, then all else constant (weather, real energy prices, shell efficiency, etc.), energy consumption per heat pump would average about only 9 percent less. While some petroleum products were above 1990 levels, emissions from total petroleum, as well as coal and natural gas, were below 1990 levels in 2009.

Adjusting for the size of housing units

Information derived from RECS 2005 indicates that new construction (post-1990) is on average roughly 26 percent larger than the existing stock of housing. Estimates for the size of each new home built in the projection period vary by type and region, and are determined by a log-trend projection based on historical data from the Bureau of the Census. [3] For existing structures, it is assumed that about 1 percent of households that existed in 2005 add about 600 square feet to the heated floor space in each year of the projection period. [4] The energy consumption for space heating, air conditioning, and lighting is assumed to increase with the square footage of the structure. This results in an increase in the average size of a housing unit from 1,632 to 1,934 square feet from 2005 through 2035.

Adjusting for weather and climate

Weather in any given year always includes short-term deviations from the expected longer-term average (or climate). Recognition of the effect of weather on space heating and air conditioning is necessary to avoid inadvertently projecting abnormal weather conditions into the future. The residential module adjusts space heating and air conditioning UECs by Census Division using data on heating and cooling degree-days (HDD and CDD). A 10 percent increase in HDD would increase space heating consumption by 10 percent over what it would have otherwise been. Over the projection period, the residential module uses a 10-year average for heating and cooling degree-days by Census Division, adjusted to account for projected changes population by State.

Short-term price effect and efficiency rebound

It is assumed that energy consumption for a given end-use service is affected by the marginal cost of providing that service. That is, all else equal, a change in the price of a fuel will have an opposite, but less than proportional, effect on fuel consumption. The current value for the short-term elasticity parameter for non-electric fuels is -0.15. [5] This value implies that for a 1 percent increase in the price of a fuel, there will be a corresponding decrease in energy consumption of -0.15 percent. Changes in equipment efficiency also affect the marginal cost of providing a service. For example, a 10 percent increase in efficiency will reduce the cost of providing the end-use service by 10 percent. Based on the short-term efficiency rebound parameter, the demand for the service will rise by 1.5 percent (-10 percent multiplied by -0.15). Only space heating, cooling, and lighting are assumed to be affected by both elasticities and the efficiency rebound effect. For electricity, the short-term elasticity parameter is set to -0.30 to account for successful deployment of smart grid projects funded under the American Recovery and Reinvestment Act of 2009 (ARRA09).

Shell efficiency

The shell integrity of the building envelope is an important determinant of the heating and cooling load for each type of household. In the NEMS Residential Demand Module, the shell integrity is represented by an index, which changes over time to reflect improvements in the building shell. The shell integrity index is dimensioned by vintage of house, type of house, fuel type, service (heating and cooling), and Census Division. The age, type, location, and type of heating fuel are important factors in determining the level of shell integrity. Housing units heated with electricity tend to have less air infiltration rates than homes that use other fuels. Homes are classified by age as new (post-2005) or existing. Existing homes are represented by the RECS 2005 survey and are assigned a shell index value based on the mix of homes that exist in the base year (2005). The improvement over time in the shell integrity of these homes is a function of two factors—an assumed annual efficiency improvement and improvements made when real fuel prices increase (no price-related adjustment is made when fuel prices fall). For new construction, building shell efficiency is determined by the relative costs and energy bill savings for several levels of heating and cooling equipment, in conjunction with the building shell attributes. The packages represented in NEMS range from homes that meet the International Energy Conservation Code (IECC) [6] to homes that are built with the most efficient shell components. Shell efficiency in new homes increases over time when energy prices rise, or the cost of more efficient equipment falls, all else equal.

Legislation and regulations

American Recovery and Reinvestment Act of 2009 (ARRA09)

The ARRA09 legislation passed in February 2009 provides energy efficiency funding for Federal agencies, State Energy Programs, and block grants, as well as a sizable increase in funding for weatherization. To account for the impact of this funding, it is assumed that the total funding is aimed at increasing the efficiency of the existing housing stock. The assumptions regarding the energy savings for heating and cooling are based on evaluations of the impact of weatherization programs over time. Further, it is assumed each house requires a $2,600 investment to achieve the heating and cooling energy savings cited in [7] and that the efficiency measures last approximately 20 years. Assumptions for funding amounts and timing were revised downward and further into the future based on analysis of the weatherization program by the Inspector General of the Department of Energy [8].

The ARRA09 provisions remove the cap on the 30-percent tax credit for ground-source heat pumps, solar PV, solar thermal water heaters, and small wind turbines through 2016. Additionally, the cap for the tax credits for other energy efficiency improvements, such as windows and efficient furnaces, was increased to $1500 through the end of 2010.

Successful deployment of smart grid projects based on ARRA09 funding could stimulate more rapid investment in smart grid technologies, especially smart meters on buildings and homes, which would make consumers more responsive to electricity price changes. To represent this, the price elasticity of demand for residential electricity was increased for the services that have the ability to alter energy intensity (e.g., lighting).

Energy Improvement and Extension Act of 2008 (EIEA 2008)

EIEA 2008 extends and amends many of the tax credits that were made available to residential consumers in EPACT 2005. The tax credits for energy efficient equipment can now be claimed through 2016, while the $2000 cap for solar technologies has been removed. Additionally, the tax credit for ground-source (geothermal) heat pumps was increased to $2000. The production tax credits for dishwashers, clothes washers, and refrigerators were extended by one to two years, depending on the efficiency level and product. See the EPACT 2005 section below for more details about product coverage.

Energy Independence and Security Act of 2007 (EISA 2007)

EISA 2007 contains several provisions that impact projections of residential energy use. Standards for general service incandescent light bulbs are phased-in over 2012-2014, with a more restrictive standard specified in 2020. It is estimated that these standards require 29 percent less watts per bulb in the first phase-in, increasing to 67 percent in 2020. EISA also updates the dehumidifier standard specified in EPACT 2005, resulting in 7 percent increase in electricity savings relative to the EPACT 2005 requirement. New efficiency standards for external power supplies are set for July 1, 2008, reducing electricity use in both the active and no-load modes. Standards are also set for boilers (September 2012) and dishwashers (January 2010). Lastly, DOE is instructed to create standards for manufactured housing, requiring compliance to the latest International Energy Conservation Code (IECC) by the end of 2011.

Energy Policy Act of 2005 (EPACT05)

The passage of the EPACT05 in August 2005 provides additional minimum efficiency standards for residential equipment and provides tax credits to producers and purchasers of energy efficient equipment and builders of energy efficient homes. The standards contained in EPACT05 include: 190 watt maximum for torchiere lamps in 2006; dehumidifier standards for 2007 and 2012; and ceiling fan light kit standards in 2007. For manufactured homes that are 30 percent better than the latest code, a $1000 tax credit can be claimed in 2006 and 2007. Likewise, builders of homes that are 50 percent better than code can claim a $2000 credit over the same period. The builder tax credits and production tax credits are assumed to be passed through to the consumer in the form of lower purchase cost. EPACT05 includes production tax credits for energy efficient refrigerators, dishwashers, and clothes washers in 2006 and 2007, with dollar amounts varying by type of appliance and level of efficiency met, subject to annual caps. Consumers can claim a 10 percent tax credit in 2006 and 2007 for several types of appliances specified by EPACT05, including: energy efficient gas, propane, or oil furnaces or boilers, energy efficient central air conditioners, air and ground source heat pumps, hot water heaters, and windows. Lastly, consumers can claim a 30 percent tax credit in 2006 and 2007 for purchases of solar PV, solar water heaters, and fuel cells, subject to a cap.

National Appliance Energy Conservation Act of 1987

The Technology Choice Submodule incorporates equipment standards established by the National Appliance Energy Conservation Act of 1987 (NAECA). Some of the NAECA standards implemented in the module include: a Seasonal Energy Efficiency Rating (SEER) of 13.0 for central air conditioners and heat pumps; an Annual Fuel Utilization Efficiency (energy output over energy input) of 0.80 for oil and gas furnaces; an Efficiency Factor of 0.90 for electric water heaters; and refrigerator standards that set consumption limits to 510 kilowatt-hours per year in 2002.

Residential alternative cases

Technology cases

In addition to the *AEO2011* Reference case, three side cases were developed to examine the effect of equipment and building standards on residential energy use—a 2010 Technology case, a High technology case, and a Best Available case. These side cases were analyzed in stand-alone (not integrated with the supply modules) NEMS runs and thus do not include supply-responses to the altered residential consumption patterns of the three cases. *AEO2011* also analyzed Integrated Low Technology and High Technology cases. The Integrated Low Technology case combines the 2010 Technology cases of the four end-use demand sectors, the Electricity Low Fossil Technology case, and the assumption of renewable technologies fixed at 2010 levels. The Integrated High Technology case uses the same approach, but for high technology.

The 2010 Technology case assumes that all future equipment purchases are made based only on equipment available in 2010. This case further assumes that existing building shell efficiencies will not improve beyond 2010 levels.

The High Technology case assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than the Reference case. Equipment assumptions developed by engineering technology experts, reflect the potential impact on technology given increased research and development into more advanced technologies [9]. In the High Technology case, all new construction is assumed to meet Energy Star specifications after 2015. In addition, consumers are assumed to evaluate energy efficiency investments at 7 percent real.

The Best Available Technology case assumes that all equipment purchases from 2010 forward are based on the highest available efficiency in the High Technology case in a particular simulation year, disregarding the economic costs of such a case. This case is designed to show how much the choice of the highest-efficiency equipment could affect energy consumption. In this case, all new construction is built to the most efficient specifications after 2010. In addition, consumers are assumed to evaluate energy efficiency investments at 7 percent real.

Notes and sources

[1] The Model Documentation Report contains additional details concerning model structure and operation. Refer to Energy Information Administration, Model Documentation Report: Residential Sector Demand Module of the National Energy Modeling System, DOE/EIA-M067(2010), (May 2010).

[2] Among the explanations often mentioned for observed high average implicit discount rates are: market failures, (i.e., cases where incentives are not properly aligned for markets to result in purchases based on energy economics alone); unmeasured technology costs (i.e., extra costs of adoption which are not included or difficult to measure like employee down-time); characteristics of efficient technologies viewed as less desirable than their less efficient alternatives (such as equipment noise levels or lighting quality characteristics); and the risk inherent in making irreversible investment decisions. Examples of market failures/barriers include: decision makers having less than complete information, cases where energy equipment decisions are made by parties not responsible for energy bills (e.g., landlord/tenants, builders/home buyers), discount horizons which are truncated (which might be caused by mean occupancy times that are less than the simple payback time and that could possibly be classified as an information failure), and lack of appropriate credit vehicles for making efficiency investments. The use of high implicit discount rates in NEMS merely recognizes that such rates are typically found to apply to energy-efficiency investments.

[3] U.S. Bureau of Census, Series C25 Data from various years of publications.

[4] Sources: U.S. Bureau of Census, Annual Housing Survey 2001 and Professional Remodler, 2002 Home Remodeling Study.

[5] See Dahl, Carol, A Survey of Energy Demand Elasticities in Support of the Development of the NEMS, October 1993.

[6] The IECC established guidelines for builders to meet specific targets concerning energy efficiency with respect to heating and cooling load.

[7] Oak Ridge National Laboratory, Estimating the National Effects of the U.S. Department of Energy's Weatherization Assistance Program with State-Level Data: A Metaevaluation Using Studies from 1993 to 2005, September 2005.

[8] U.S. Department of Energy, Office of Inspector General, Office of Audit Services, Special Report: Progress in Implementing the Department of Energy's Weatherization Assistance Program under the American Recovery and Reinvestment Act, February 2010.

[9] The high technology assumptions are based on Energy Information Administration, (*Technology Forecast Updates-Residential and Commercial Building Technologies-Advanced Adoption Case*) (Navigant Consulting, September 2007).

Commercial Demand Module

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The NEMS Commercial Sector Demand Module generates projections of commercial sector energy demand through 2035. The definition of the commercial sector is consistent with EIA's State Energy Data System (SEDS). That is, the commercial sector includes business establishments that are not engaged in transportation or in manufacturing or other types of industrial activity (e.g., agriculture, mining or construction). The bulk of commercial sector energy is consumed within buildings; however, street lights, pumps, bridges, and public services are also included if the establishment operating them is considered commercial. Since most of commercial energy consumption occurs in buildings, the commercial module relies on the data from the EIA Commercial Buildings Energy Consumption Survey (CBECS) for characterizing the commercial sector activity mix as well as the equipment stock and fuels consumed to provide end use services [1].

The commercial module projects consumption by fuel [2] at the Census division level using prices from the NEMS energy supply modules and macroeconomic variables from the NEMS Macroeconomic Activity Module (MAM), as well as external data sources (technology characterizations, for example). Energy demands are projected for ten end-use services [3] for eleven building categories [4] in each of the nine Census divisions (see Figure 5). The model begins by developing projections of floorspace for the 99 building category and Census division combinations. Next, the ten end-use service demands required for the projected floorspace are developed. The electricity generation and water and space heating supplied by distributed generation and combined heat and power technologies are projected. Technologies are then chosen to meet the projected service demands for the seven major end uses [5]. Once technologies are chosen, the energy consumed by the equipment stock (both existing and purchased equipment) is developed to meet the projected end-use service demands [6].

Key assumptions

The key assumptions made by the commercial module are presented in terms of the flow of the calculations described above. The sections below summarize the assumptions in each of the commercial module submodules: floorspace, service demand, distributed generation, technology choice, and end-use consumption. The submodules are executed sequentially in the order presented, and the outputs of each submodule become the inputs to subsequently executed submodules. As a result, key projection drivers for the floorspace submodule are also key drivers for the service demand submodule, and so on.

Floorspace submodule

Floorspace is projected by starting with the previous year's stock of floorspace and eliminating a portion to represent the age-related removal of buildings. Total floorspace is the sum of the surviving floorspace plus new additions to the stock derived from the MAM floorspace growth projection [7].

Existing floorspace and attrition

Existing floorspace is based on the estimated floorspace reported in the 2003 Commercial Buildings Energy Consumption Survey (Table 5.1). Over time, the 2003 stock is projected to decline as buildings are removed from service (floorspace attrition). Floorspace attrition is estimated by a logistic decay function, the shape of which is dependent upon the values of two parameters: average building lifetime and gamma. The average building lifetime refers to the median expected lifetime of a particular building type. The gamma parameter corresponds to the rate at which buildings retire near their median expected lifetime. The current values for the average building lifetime and gamma vary by building type as presented in Table 5.2 [8].

New construction additions to floorspace

The commercial module develops estimates of projected commercial floorspace additions by combining the surviving floorspace estimates with the total floorspace projection from MAM. A total NEMS floorspace projection is calculated by applying the MAM assumed floorspace growth rate within each Census division and MAM building type to the corresponding NEMS Commercial Demand Module's building types based on the CBECS building type shares. The NEMS surviving floorspace from the previous year is then subtracted from the total NEMS floorspace projection for the current year to yield new floorspace additions [9].

Service demand submodule

Once the building stock is projected, the Commercial Demand module develops a projection of demand for energy-consuming services required for the projected floorspace. The module projects service demands for the following explicit end-use services: space heating, space cooling, ventilation, water heating, lighting, cooking, refrigeration, personal computer office equipment, and other office equipment [10]. The service demand intensity (SDI) is measured in thousand Btu of end-use service demand per square foot and differs across service, Census division, and building type. The SDIs are based on a hybrid engineering and statistical approach of CBECs consumption data [11]. Projected service demand is the product of square feet and SDI for all end uses across the eleven building categories with adjustments for changes in shell efficiency for space heating and cooling.

Table 5.1. 2003 Total floorspace by Census Division and principal building activity
million of square feet

	Assembly	Education	Food Sales	Food Service	Health Care	Lodging	Large Office	Small Office	Merc/ Service	Warehouse	Other	Total
New England	431	299	75	45	48	374	282	320	819	411	351	3,452
Middle Atlantic	1,243	1,384	163	127	310	797	1,523	1,065	1,641	1,112	1,177	10,543
East North Central	1,355	1,990	218	248	316	549	1,297	1,129	2,148	2,023	1,152	12,424
West North Central	772	552	102	206	123	595	219	704	1,045	994	369	5,580
South Atlantic	1,161	2,445	223	433	469	939	1,173	1,065	3,391	1,836	865	13,999
East South Central	546	341	67	99	134	368	195	371	985	390	223	3,719
West South Central	965	1,198	197	232	235	387	916	501	2,076	1,740	575	9,022
Mountain	411	640	64	32	94	438	230	535	1,087	506	168	4,207
Pacific	809	1,027	146	232	176	649	1,028	915	2,051	1,066	515	8,613
Total United States	7,693	9,874	1,255	1,654	1,905	5,096	6861	6,605	15,242	10,078	5,395	71,658

Note: Totals may not equal sum of components due to independent rounding.
Source: U.S. Energy Information Administration, 2003 Commercial Buildings Energy Consumption Survey Public Use Data.

Table 5.2. Floorspace attrition parameters

	Assembly	Education	Food Sales	Food Service	Health Care	Lodging	Large Office	Small Office	Merc/ Service	Warehouse	Other
Median Expected Lifetime (years)	55	62	55	50	55	53	65	58	50	58	60
Gamma	2.2	2.1	2.3	2.0	2.5	2.1	2.0	2.0	2.2	2.0	2.3

Source: U.S. Energy Information Administration, Commercial Buildings Energy Consumption Survey 2003, 1999, 1995, 1992, and 1989 Public Use Data, 1986 Nonresidential Buildings Energy Consumption Survey, McGraw-Hill Construction Dodge Annual Starts - non residential building starts, Northwest Energy Efficiency Alliance, Assessment of the Commercial Building Stock in the Pacific Northwest, KEMA-XENERGY, Inc., March 2004, and public information on demolitions.

Shell efficiency

The shell integrity of the building envelope is an important determinant of the heating and cooling loads for each type of building. In the NEMS Commercial Demand Module, the shell efficiency is represented by separate building shell heating and cooling factors which change over time to reflect improvements in the building shell. The factors, dimensioned by building type and Census division, affect the space heating and cooling service demand intensities causing changes in fuel consumed for these services as the shell integrity improves. In the *AEO2011* Reference case building shells for new construction built in 2003 are up to 49 percent more efficient with respect to heating and up to 30 percent more efficient with respect to cooling relative to the average shell for existing buildings of the same type. Over the projection horizon, new building shells improve in efficiency by 14 percent relative to their efficiency in 2003. For existing buildings, efficiency is assumed to increase by 6 percent over the 2003 stock average.

Distributed generation and combined heat and power

Program driven installations of solar photovoltaic systems are based on information from DOE's Photovoltaic program as well as DOE and industry news releases, State-level program information, the National Renewable Energy Laboratory's Renewable Electric Plant Information System, and the Interstate Renewable Energy Council's annual report on U.S. solar market trends. Historical data from Form EIA-860, Annual Electric Generator Report, are used to derive electricity generation for 2004 through 2009 by Census division, building type and fuel. A projection of distributed generation and combined heat and power (CHP) of electricity is developed based on the economic returns projected for distributed generation and CHP technologies. The model uses a detailed cash-flow approach to estimate the internal rate of return for an investment. Penetration assumptions for distributed generation and CHP technologies are a function of the estimated internal rate of return relative to purchased electricity. Table 5.3 provides the cost and performance parameters for representative distributed generation and CHP technologies.

The model also incorporates endogenous "learning" for new distributed generation and CHP technologies, allowing for declining technology costs as shipments increase. For fuel cell and photovoltaic systems, parameter assumptions for the *AEO2011* Reference case result in a 13 percent reduction in capital costs each time the number of units shipped to the buildings sectors (residential and commercial) doubles. Doubling the number of microturbines shipped results in a 10 percent reduction in capital costs and doubling the number of distributed wind systems shipped results in a 3 percent reduction.

Technology Choice Submodule

The technology choice submodule develops projections of the results of the capital purchase decisions for equipment fueled by the three major fuels (electricity, natural gas, and distillate fuel). Capital purchase decisions are driven by assumptions concerning behavioral rule proportions and time preferences, described below, as well as projected fuel prices, average utilization of equipment (the capacity factors), relative technology capital costs, and operating and maintenance (O&M) costs.

Decision types

In each projection year, equipment is potentially purchased for three "decision types". Equipment must be purchased for newly added floorspace and to replace the portion of equipment in existing floorspace that is projected to wear out [12]. Equipment is also potentially purchased for retrofitting equipment that has become economically obsolete. The purchase of retrofit equipment occurs only if the annual operating costs of a current technology exceed the annualized capital and operating costs of a technology available as a retrofit candidate.

Behavioral rules

The commercial module allows the use of three alternate assumptions about equipment choice behavior. These assumptions constrain the equipment selections to three choice sets, which are progressively more restrictive. The choice sets vary by decision type and building type:

- Unrestricted Choice Behavior - This rule assumes that commercial consumers consider all types of equipment that meet a given service, across all fuels, when faced with a capital purchase decision.
- Same Fuel Behavior - This rule restricts the capital purchase decision to the set of technologies that consume the same fuel that currently meets the decision maker's service demand.
- Same Technology Behavior - Under this rule, commercial consumers consider only the available models of the same technology and fuel that currently meet service demand, when facing a capital stock decision.

Under any of the above three behavior rules, equipment that meets the service at the lowest annualized lifecycle cost is chosen. Table 5.4 illustrates the proportions of floorspace subject to the different behavior rules for space heating technology choices in large office buildings.

Time preferences

Commercial building owners' time preferences regarding current versus future expenditures are assumed to be distributed among seven alternate time preference premiums. Adding the risk-adjusted time preference premiums to the 10-year Treasury Note rate from MAM results in implicit discount rates, also known as hurdle rates, applicable to the assumed proportions of commercial floorspace. The effect of the use of this distribution of discount rates is to prevent a single technology from dominating purchase decisions in the lifecycle cost comparisons. The distribution used for *AEO2011* assigns some floorspace a very high discount or hurdle rate to simulate floorspace which will never retrofit existing equipment and which will only purchase equipment with the lowest capital cost. Discount rates for the remaining six segments of the distribution get progressively lower, simulating increased sensitivity to the fuel costs of the equipment that is purchased. The share of floorspace assigned to each rate in the distribution varies by end-use service. Table 5.5 illustrates the distribution of time preference premiums for space heating and lighting in 2015. The proportion of floorspace assumed for the 0.0 time preference premium represents an estimate of the Federally owned commercial floorspace that is subject to purchase decisions in a given year. The Federal sector is expected to purchase energy-efficient equipment to meet the Federal buildings performance standards of the Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007 whenever cost effective. For Federal purchase decisions relating to energy conservation, cost effectiveness is determined using a discount rate based on long-term Treasury bond rates, approximated in the commercial module by the 10-year Treasury Note rate. For lighting, the proportion of floorspace assumed for the 0.0 time preference premium is increased to include all Federal floorspace starting in 2009 to represent the EISA 2007 provision that all Federal buildings be equipped with energy efficient lighting fixtures and bulbs to the maximum extent feasible, including when replacing bulbs in existing fixtures.

Table 5.3. Capital cost and performance parameters of selected commercial distributed generation technologies

Technology Type	Year of Introduction	Average Generating Capacity (kW_{DC})	Electrical Efficiency	Combined Efficiency (Elec. + Thermal)	Installed Capital Cost (2009 $ per kW_{DC})*	Service Life (Years)
Solar Photovoltaic						
	2010	32	0.15	N/A	$6,874	30
	2015	35	0.18	N/A	$5,109	30
	2025	40	0.20	N/A	$4,067	30
	2035	45	0.20	N/A	$3,837	30
Fuel Cell						
	2010	200	0.42	0.65	$7,199	20
	2015	200	0.48	0.66	$5,019	20
	2025	200	0.51	0.69	$4,016	20
	2035	200	0.54	0.73	$3,180	20
Natural Gas Engine						
	2010	334	0.30	0.82	$1,780	20
	2015	334	0.31	0.85	$1,630	20
	2025	334	0.30	0.87	$1,251	20
	2035	334	0.30	0.91	$831	20
Oil-fired Engine						
	2010	300	0.34	0.73	$1,784	20
	2015	300	0.34	0.74	$1,746	20
	2025	300	0.35	0.80	$1,669	20
	2035	300	0.36	0.78	$1,592	20
Natural Gas Turbine						
	2010	3510	0.25	0.76	$1,890	20
	2015	3510	0.25	0.77	$1,858	20
	2025	3510	0.25	0.80	$1,760	20
	2035	3510	0.25	0.82	$1,645	20
Natural Gas Microturbine						
	2010	200	0.32	0.61	$2,414	20
	2015	200	0.34	0.67	$2,098	20
	2025	200	0.37	0.73	$1,467	20
	2035	200	0.40	0.80	$836	20
Wind						
	2010	32	0.13	N/A	$5,224	30
	2015	35	0.13	N/A	$4,715	30
	2025	40	0.13	N/A	$3,973	30
	2035	50	0.13	N/A	$3,627	30

*The original source documents presented solar photovoltaic costs in 2008 dollars, all other technologies in 2010 dollars. Costs for solar photovoltaic, fuel cell, microturbine, and wind technologies include learning effects.
Sources: U.S. Energy Information Administration, Commercial and Industrial CHP Technology Cost and Performance Data Analysis for EIA SENTECH, Inc., and SAIC, Inc., June 2010, U.S. Energy Information Administration, Photovoltaic (PV) Cost and Performance Characteristics for Residential and Commercial Applications Final Report, ICF International, August 2010, and U.S. Energy Information Administration, The Cost and Performance of Distributed Wind Turbines, 2010-35 Final Report, ICF International, August 2010.

Table 5.4. Assumed behavior rules for choosing space heating equipment in large office buildings
percent

	Unrestricted	Same Fuel	Same Technology	Total
New Equipment Decision	21	30	49	100
Replacement Decision	7	31	62	100
Retrofit Decision	1	4	95	100

Source: U.S. Energy Information Administration, Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System, DOE/EIA-M066(2011) (June 2011).

Table 5.5. Assumed distribution of risk-adjusted time preference premiums for space heating and lighting equipment in 2015
percent

Proportion of Floorspace-Space Heating (2015)	Proportion of Floorspace-Lighting (2015)	Time Preference Premium
27.0	27.0	1000.0
23.0	23.0	100
19.0	18.6	45
18.6	18.6	25
10.7	8.8	15
1.5	1.5	6.5
0.2	2.5	0.0
100.0	100.0	--

Source: U.S. Energy Information Administration, Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System, DOE/EIA-M066(2011) (June 2011).

The distribution of hurdle rates used in the commercial module is also affected by changes in fuel prices. If a fuel's price rises relative to its price in the base year (2003), the nonfinancial portion of each hurdle rate in the distribution decreases to reflect an increase in the relative importance of fuel costs, expected in an environment of rising prices. Parameter assumptions for *AEO2011* result in a 30 percent reduction in the nonfinancial portion of a hurdle rate if the fuel price doubles. If the risk-adjusted time preference premium input by the model user results in a hurdle rate below the assumed financial discount rate for the commercial sector, 15 percent, with base year fuel prices (such as the rate given in Table 5.5 for the Federal sector), no response to increasing fuel prices is assumed.

Technology characterization database

The technology characterization database organizes all relevant technology data by end use, fuel, and Census division. Equipment is identified in the database by a technology index as well as a vintage index, the index of the fuel it consumes, the index of the service it provides, its initial market share, the Census division index for which the entry under consideration applies, its efficiency (or coefficient of performance or efficacy in the case of lighting equipment), installed capital cost per unit of service demand satisfied, operating and maintenance cost per unit of service demand satisfied, average service life, year of initial availability, and last year available for purchase. Equipment may only be selected to satisfy service demand if the year in which the decision is made falls within the window of availability. Equipment acquired prior to the lapse of its availability continues to be treated as part of the existing stock and is subject to replacement or retrofitting. This flexibility in limiting equipment availability allows the direct modeling of equipment efficiency standards. Table 5.6 provides a sample of the technology data for space heating in the New England Census division.

An option has been included to allow endogenous price-induced technological change in the determination of equipment costs and availability for the menu of equipment. This concept allows future technologies faster diffusion into the market place if fuel prices increase markedly for a sustained period of time. The option was not exercised for the *AEO2011* model runs.

End-Use Consumption Submodule

The end-use consumption submodule calculates the consumption of each of the three major fuels (electricity, natural gas, and distillate fuel oil) for the ten end-use services plus fuel consumption for combined heat and power and district services. For the ten end-use services, energy consumption is calculated as the end-use service demand met by a particular type of equipment divided by its efficiency and summed over all existing equipment types. This calculation includes dimensions for Census division, building type, and fuel. Consumption of the five minor fuels (residual fuel oil, liquid petroleum gas, motor gasoline, kerosene, and coal) is projected based on historical trends.

Equipment efficiency

The average energy consumption of a particular appliance is based initially on estimates derived from the 2003 CBECS. As the stock efficiency changes over the model simulation, energy consumption decreases nearly, but not quite proportionally to the efficiency increase. The difference is due to the calculation of efficiency using the harmonic average and also the efficiency rebound effect discussed below. For example, if on average, electric heat pumps are now 10 percent more efficient than in 2003, then all else constant (weather, real energy prices, shell efficiency, etc.), energy consumption per heat pump would now average about 9 percent less. The Service Demand and Technology Choice Submodules together determine the average efficiency of the stocks used in adjusting the initial average energy consumption.

Adjusting for weather and climate

Weather in any given year always includes short-term deviations from the expected longer-term average (or climate). Recognition of the effect of weather on space heating and air conditioning is necessary to avoid projecting abnormal weather conditions into the future. In the commercial module, proportionate adjustments are made to space heating and air conditioning demand by Census division. These adjustments are based on National Oceanic and Atmospheric Administration (NOAA) data for Heating Degree Days (HDD) and Cooling Degree Days (CDD). A 10 percent increase in HDD would increase space heating consumption by 10 percent over what it would have been otherwise. The commercial module uses a 10-year average for HDD and CDD by Census division, adjusted over the projection period by projections for State population shifts.

Short-term price effect and efficiency rebound

It is assumed that energy consumption for a given end-use service is affected by the marginal cost of providing that service. That is, all else equal, a change in the price of a fuel will have an inverse, but less than proportional, effect on fuel consumption. The current value for the short-term price elasticity parameter is -0.25 for all major end uses except refrigeration. A value of -0.1 is currently used for commercial refrigeration. A value of -0.05 is currently used for PC and non-PC office equipment and other minor uses of electricity. For example, for lighting this value implies that for a 1 percent increase in the price of a fuel, there will be a corresponding decrease in energy consumption of 0.25 percent. Another way of affecting the marginal cost of providing a service is through equipment efficiency. As equipment efficiency changes over time, so will the marginal cost of providing the end-use service. For example, a 10 percent increase in efficiency will reduce the cost of providing the service by 10 percent. The short-term elasticity parameter for efficiency rebound effects is -0.15 for affected end uses; therefore, the demand for the service will rise by 1.5 percent (-10 percent x -0.15). Currently, all services are affected by the short-term price effect and services affected by efficiency rebound are space heating and cooling, water heating, ventilation and lighting.

Legislation and regulations

American Recovery and Reinvestment Act of 2009 (ARRA09)

The ARRA09 legislation passed in February 2009 provides energy efficiency funding for Federal agencies, State Energy Programs, and block grants. To account for the impact of this funding, States are assumed to adopt and enforce the ASHRAE 90.1-2007 standard by 2018 for building shell measures and all Public buildings (Federal, state, and local) are assumed to use the 10-year treasury note rate for purchase decisions related to both new construction and replacement equipment while stimulus funding is available. A percentage of the State Energy Program and Conservation Block Grant funding is assumed to be used for solar photovoltaic and small wind turbine installations. Additional stimulus funding is applied to fuel cell installations.

The ARRA09 provisions remove the cap on the 30-percent Business Investment Tax Credit for wind turbines. The Investment Tax Credit is still available for systems installed through 2016. These credits are directly incorporated into the cash-flow approach for distributed generation systems.

Energy Improvement and Extension Act of 2008 (EIEA08)

The EIEA08 legislation passed in October 2008 extends the Business Investment Tax Credit provisions of the Energy Policy Act of 2005 and expands the credit to include additional technologies. The Business Investment Tax Credits of 30 percent for solar energy systems and fuel cells and 10 percent for microturbines are extended through 2016. The cap on the fuel cell credit has been increased from $500 to $1,500 per half kilowatt of capacity. The EIEA08 provisions expand the Investment Tax Credit to

Table 5.6. Capital cost and efficiency ratings of selected commercial space heating equipment[1]

Equipment Type	Vintage	Efficiency[2]	Capital Cost ($2007 per Mbtu/hour)[3]	Maintenance Cost ($2007 per Mbtu/hour)[3]	Service Life (Years)
Electric Rooftop Heat Pump	2007 - typical	3.2	$72.78	$1.39	15
	2007 - high efficiency	3.4	$96.67	$1.39	15
	2010 - typical (standard)	3.3	$76.67	1.39	15
	2010 - high efficiency	3.4	$96.67	$1.39	15
	2020 - typical	3.3	$76.67	$1.39	15
	2020 - high efficiency	3.4	$96.67	$1.39	15
Ground-source Heat Pump	2007 - typical	3.5	$140.00	$16.80	20
	2007 - high efficiency	4.9	$170.00	$16.80	20
	2010 - typical	3.5	$140.00	$16.80	20
	2010 - high efficiency	4.9	$170.00	$16.80	20
	2020 - typical	4.0	$140.00	$16.80	20
	2020 - high efficiency	4.9	$170.00	$16.80	20
Electric Boiler	Current typical	0.98	$17.53	$0.58	21
Packaged Electric	Typical	0.96	$16.87	$3.95	18
Natural Gas Furnace	Current Standard	0.80	$9.35	$0.97	20
	2007 - high efficiency	0.82	$9.90	$0.94	20
	2020 - typical	0.81	$9.23	$0.96	20
	2020 -high efficiency	0.90	$11.57	$0.86	20
	2030 - typical	0.82	$9.12	$0.94	20
	2030 - high efficiency	0.91	$11.44	$0.85	20
Natural Gas Boiler	Current Standard	0.78	$21.56	$0.48	25
	2007 - mid efficiency	0.84	$24.35	$0.45	25
	2007 - high efficiency	0.95	$38.28	$0.50	25
	2012 - standard	0.80	$21.02	$0.47	25
Natural Gas Heat Pump	2007 - absorption	1.4	$158.33	$2.50	15
	2010 - absorption	1.4	$158.33	$2.50	15
	2020 - absorption	1.4	$158.33	$2.50	15
Distillate Oil furnace	Currrent Standard	0.81	$11.14	$0.96	20
	2020 - typical	0.81	$11.14	$0.96	20
Distillate Oil Boiler	Current Standard	0.80	$17.19	$0.15	20
	2007 - high efficiency	0.87	$19.16	$0.14	20
	2012 - standard	0.81	$16.98	$0.15	20

[*]Equipment listed is for the New England Census division, but is also representative of the technology data for the rest of the U.S. See the source reference below for the complete set of technology data.
[2]Efficiency measurements vary by equipment type. Electric rooftop air-source heat pumps, ground source and natural gas heat pumps are rated for heating performance using coefficient of performance; natural gas and distillate furnaces and boilers are based on Thermal Efficiency.
[3]Capital and maintenance costs are given in 2007 dollars.
Source: U.S. Energy Information Administration, "EIA - Technology Forecast Updates - Residential and Commercial Building Technologies - Reference Case Second Edition (Revised)", Navigant Consulting, Inc., Reference Number 20070831.1, September 2007.

include a 10-percent credit for CHP systems and ground-source heat pumps and a 30-percent credit for wind turbines with the wind credit capped at $4,000. The expanded credits are available for systems installed through 2016. These credits are directly incorporated into the cash-flow approach for distributed generation systems, including CHP, and factored into the installed capital cost assumptions for solar hot water heaters and ground-source heat pumps.

Energy Independence and Security Act of 2007 (EISA07)

The EISA07 legislation passed in December 2007 provides standards for the following explicitly modeled commercial equipment. The EISA07 requires specific energy efficiency measures in commercial walk-in coolers and walk-in freezers effective January 1, 2009. Incandescent and halogen lamps must meet standards for maximum allowable wattage based on lumen output starting in 2012 and metal halide lamp fixtures using lamps between 150 and 500 watts are required to have a minimum ballast efficiency ranging from 88 to 94 percent, depending on ballast type, effective January 1, 2009.

The EISA07 requirement for Federal buildings to use energy efficient lighting fixtures and bulbs to the maximum extent possible is represented by adjusting the proportion of the commercial sector assumed to use the 10-year Treasury note rate as an implicit discount or hurdle rate for lighting.

Energy Policy Act of 2005 (EPACT05)

The passage of the EPACT05 in August 2005 provides additional minimum efficiency standards for commercial equipment. Some of the standards for explicitly modeled equipment, effective January 1, 2010, include: an Energy Efficiency Rating (EER) ranging from 10.8 to 11.2 for small package air conditioning and heating equipment; daily electricity consumption limits by volume for commercial refrigerators, freezers, and refrigerator-freezers; and electricity consumption limits per 100 pounds of ice produced based on equipment type and capacity for automatic ice makers. The EPACT05 adds standards for medium base compact fluorescent lamps effective January 1, 2006, for ballasts for Energy Saver fluorescent lamps effective in 2009 and 2010, and bans the manufacture or import of mercury vapor lamp ballasts effective January 1, 2008.

Several efficiency standards in the EPACT05 pertain to equipment not explicitly represented in the NEMS Commercial Demand Module. For low voltage dry-type transformers, effects of the standard are included in estimating the share of projected miscellaneous electricity use attributable to transformer losses. For illuminated exit signs, traffic signals, and commercial prerinse spray valves, assumed energy reductions are calculated based on per-unit savings relative to a baseline unit and the estimated share of installed units and sales that already meet the standard. Total projected reductions are phased in over time to account for stock turnover. Under the EPACT05 standards, illuminated exit signs and traffic signal modules must meet ENERGY STAR program requirements as of January 1, 2006. The requirements limit input power demand to 5 watts or less per face for exit signs. Nominal wattages for traffic signal modules are limited to 8 to 15 watts, based on module type. Effective January 1, 2007, low voltage dry-type distribution transformers are required to meet the National Electrical Manufacturers Association Class I Efficiency Levels with minimum efficiency levels ranging from 97 percent to 98.9 percent based on output. Commercial prerinse spray valves[13] must have a maximum flow rate of 1.6 gallons per minute, effective January 1, 2006 with energy reductions attributed to hot water use.

The EPACT05 expands the Business Investment Tax Credit to 30 percent for solar property installed in 2006 and 2007. Business Investment Tax Credits of 30 percent for fuel cells and 10 percent for microturbine power plants are also available for property installed in 2006 and 2007. The EPACT05 tax credit provisions were extended in December 2006 to cover equipment installed in 2008. These credits are directly incorporated into the cash-flow approach for distributed generation systems and factored into the installed capital cost assumptions for solar hot water heaters.

Energy Policy Act of 1992 (EPACT92)

A key assumption incorporated in the technology selection process is that the equipment efficiency standards described in the EPACT92 constrain minimum equipment efficiencies. The effects of standards are modeled by modifying the technology database to eliminate equipment that no longer meets minimum efficiency requirements. Some of the EPACT92 standards implemented in the module include: gas and oil-fired boilers—minimum combustion efficiency of 0.8 and 0.83, respectively, amended to minimum thermal efficiency of 0.8 and 0.81, respectively, in 2012; gas and oil-fired furnaces—minimum thermal efficiency of 0.8 and 0.81, respectively; electric water heaters—minimum energy factor of 0.85; and gas and oil water heaters—minimum thermal efficency of 0.8 and 0.78, respectively. A fluorescent lamp ballast standard effective in 2005, mandates electronic ballasts with a minimum ballast efficacy factor of 1.17 for 4-foot, 2-lamp ballasts and 0.63 for 8-foot, 2-lamp ballasts. Fluorescent lamps and incandescent reflector lamb bulbs must meet amended standard levels for minimum average lamp efficacy in 2012. Recent updates for commercial refrigeration equipment include maximum energy consumption standards for refrigerated vending machines and display cases based on volume.

The 10 percent Business Investment Tax Credit for solar energy property included in EPACT92 is directly incorporated into the cash-flow approach for projecting distributed generation by commercial photovoltaic systems. For solar hot water heaters, the tax credit is factored into the installed capital cost assumptions used in the technology choice submodule.

Energy efficiency programs

Several energy efficiency programs affect the commercial sector. These programs are designed to stimulate investment in more efficient building shells and equipment for heating, cooling, lighting, and other end uses. The commercial module includes several features that allow projected efficiency to increase in response to voluntary programs (e.g., the distribution of risk-adjusted time preference premiums and shell efficiency parameters). Retrofits of equipment for space heating, air conditioning and lighting are incorporated in the distribution of premiums given in Table 5.5. Also the shell efficiency of new and existing buildings is assumed to increase from 2003 through 2035. Shells for new buildings increase in efficiency by 14 percent over this period, while shells for existing buildings increase in efficiency by 6 percent.

Commercial alternative cases

Technology cases

In addition to the *AEO2011* Reference case, three side cases were developed to examine the effect of equipment and building standards on commercial energy use—a 2010 Technology case, a High Technology case, and a Best Available Technology case. These side cases were analyzed in stand-alone (not integrated with the NEMS demand and supply modules) buildings (residential and commercial) modules runs and thus do not include supply-responses to the altered commercial consumption patterns of the three cases. *AEO2011* also analyzed an Integrated High Technology case, which combines the High Technology cases of the four end-use demand sectors, the Electricity Low Fossil Technology Cost case, the Low Nuclear Cost case, and the Low Renewable Cost case, and an Integrated 2010 Technology case, which combines the 2010 Technology cases of the end-use demand sectors, the Electricity High Fossil Technology Cost case, the High Nuclear Cost case, and the High Renewable Cost case.

The 2010 Technology case assumes that all future equipment purchases are made based only on equipment available in 2010. This case assumes building shell efficiency to be fixed at 2010 levels. In the Reference case, existing building shells are allowed to increase in efficiency by 6 percent over 2003 levels, and new building shells improve by 14 percent by 2035 relative to new buildings in 2003.

The High Technology case assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than the Reference case. Energy efficiency investments are evaluated at 7 percent real rather than the distribution of hurdle rates assumed for the Reference case. Equipment assumptions were developed by engineering technology experts, considering the potential impact on technology given increased research and development into more advanced technologies. In the High Technology case, building shell efficiencies are assumed to improve 25 percent more than in the Reference case after 2010. Existing building shells, therefore, increase by 7.5 percent relative to 2003 levels and new building shells by 17.4 percent relative to their efficiency in 2003 by 2035.

The Best Available Technology case assumes that all equipment purchases after 2010 are based on the highest available efficiency for each type of technology in the high technology case in a particular simulation year, disregarding the economic costs of such a case. It is designed to show how much the choice of the highest-efficiency equipment could affect energy consumption. Shell efficiencies in this case are assumed to improve 50 percent more than in the Reference case after 2010, i.e., existing shells increase by 9 percent relative to 2003 levels and new building shells by 20.8 percent relative to their efficiency in 2003 by 2035.

Fuel shares, where appropriate for a given end use, are allowed to change in the technology cases as the available technologies from each technology type compete to serve certain segments of the commercial floorspace market. For example, in the Best Available Technology case, the most efficient gas furnace technology competes with the most efficient electric heat pump technology. This contrasts with the Reference case, in which, a greater number of technologies for each fuel with varying efficiencies all compete to serve the heating end use. In general, the fuel choice will be affected as the available choices are constrained or expanded, and will thus differ across the cases.

Two sensitivities that focus on electricity generation incorporate alternative assumptions for non-hydro renewable energy technologies in the power sector, the industrial sector, and the buildings sectors, including residential and commercial photovoltaic and wind systems. In each of these cases, assumptions regarding non-renewable technologies are not changed from the Reference case.

The High Renewable Cost case assumes that the cost and performance characteristics for residential and commercial photovoltaic and wind systems remain fixed at 2010 levels through the projection horizon.

The Low Renewable Cost case assumes that costs for residential and commercial photovoltaic and wind systems are 20 percent below Reference case assumptions in 2011 declining to at least 40 percent lower than Reference case cost estimates by 2035.

Notes and sources

[1] U.S. Energy Information Administration, 2003 Commercial Buildings Energy Consumption Survey (CBECS) Public Use Files, web site www.eia.doe.gov/emeu/cbecs/cbecs2003/public_use_2003/cbecs_pubdata 2003. html.

[2] The fuels accounted for by the commercial module are electricity, natural gas, distillate fuel oil, residual fuel oil, liquefied petroleum gas (LPG), coal, motor gasoline, and kerosene. Current commercial use of biomass (wood, Municipal solid waste) is also included. In addition to these fuels the use of solar energy is projected based on an exogenous estimate of existing solar photovoltaic system installations, projected installations due to State and local incentive programs, and the potential endogenous penetration of solar photovoltaic systems and solar thermal water heaters. The use of wind energy is projected based on an estimate of existing distributed wind turbines and the potential endogenous penetration of wind turbines in the commercial sector.

[3] The end-use services in the commercial module are heating, cooling, water heating, ventilation, cooking, lighting, refrigeration, PC and non-PC office equipment and a category denoted other to account for all other minor end uses.

[4] The 11 building categories are assembly, education, food sales, food services, health care, lodging, large offices, small offices, mercantile/services, warehouse and other.

[5] Minor end uses are modeled based on penetration rates and efficiency trends.

[6] The detailed documentation of the commercial module contains additional details concerning model structure and operation. Refer to U.S. Energy Information Administration, Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System, DOE/EIA M066(2011), (June 2011).

[7] The commercial floorspace equations of the Macroeconomic Activity Model are estimated using the McGraw-Hill Construction Research & Analytics database of historical floorspace estimates. The McGraw-Hill Construction estimate for commercial floorspace in the U.S. is approximately 16 percent lower than the estimate obtained from the CBECS used for the Commercial module. See F.W. Dodge, Building Stock Database Methodology and 1991 Results, Construction Statistics and Forecasts, F.W. Dodge, McGraw-Hill.

[8] The commercial module performs attrition for 9 vintages of floorspace developed using stock estimates from the previous 5 CBECS and historical floorspace additions data from McGraw-Hill Construction data.

[9] In the event that the computation of additions produces a negative value for a specific building type, it is assumed to be zero.

[10] "Other office equipment" includes copiers, fax machines, typewriters, cash registers, server computers, and other miscellaneous office equipment. A tenth category denoted other includes equipment such as elevators, medical, and other laboratory equipment, communications equipment, security equipment, transformers and miscellaneous electrical appliances. Commercial energy consumed outside of buildings and for combined heat and power is also included in the "other" category.

[11] Based on 2003 CBECS end-use-level consumption data developed using the methodology described in Estimation of Energy End-Use Intensities, web site www.eia.doe.gov/emeu/cbecs/tech_end_use.html.

[12] The proportion of equipment retiring is inversely related to the equipment life.

[13] Commercial prerinse spray valves are handheld devices used to remove food residue from dishes and flatware before cleaning.

Industrial Demand Module

The NEMS Industrial Demand Module estimates energy consumption by energy source (fuels and feedstocks) for 15 manufacturing and 6 non-manufacturing industries. The manufacturing industries are further subdivided into the energy-intensive manufacturing industries and nonenergy-intensive manufacturing industries (Table 6.1). The manufacturing industries are modeled through the use of a detailed process-flow or end-use accounting procedure, whereas the non-manufacturing industries are modeled with substantially less detail. The petroleum refining industry is not included in the Industrial Module, as it is simulated separately in the Petroleum Market Module of NEMS. The Industrial Module calculates energy consumption for the four Census Regions (see Figure 5) and disaggregates the energy consumption to the nine Census Divisions based on fixed shares from the State Energy Data System [1].

Table 6.1. Industry categories

Energy-Intensive Manufacturing		Nonenergy-Intensive Manufacturing		Non-Manufacturing	
Food products	(NAICS 311)	**Metal-based durables**		Agricultural crop production	(NAICS 111)
Paper and allied products	(NAICS 322)	Fabricated metal products	(NAICS 332)		
Bulk chemicals		Machinery	(NAICS 333)		
Inorganic	(NAICS 32512-32518)	Computer and electronic products	(NAICS 334)	Other agricultural production	(NAICS 112, 113, 115)
Organic	(NAICS 32511, 32519)	Electrical equipment and appliances	(NAICS 335)	Coal mining	(NAICS 2121)
Resins	(NAICS 3252)	Transportation equipment	(NAICS 336)	Oil and gas extraction	(NAICS 211)
Agricultural	(NAICS 3253)	**Other**		Metal and other non-metallic mining	(NAICS 2122-2123)
Glass and glass products	(NAICS 3272)	Wood products	(NAICS 321)		
Cement	(NAICS 32731)	Plastic and rubber products	(NAICS 326)	Construction	(NAICS 233-235)
Iron and steel	(NAICS 3311-3312)	Balance of manufacturing	(all remaining manufacturing NAICS)		
Aluminum	(NAICS 3313)				

NAICS = North American Industry Classification System.
Source: Office of Management and Budget, North American Industry Classification system (NAICS) - United States (Springfield, VA. National Technical Information Service).

The energy-intensive industries (food products, paper and allied products, bulk chemicals, glass and glass products, cement, iron and steel, and aluminum) are modeled in considerable detail. Each industry is modeled as three separate but interrelated components: the Process and Assembly (PA) Component, the Buildings (BLD) Component, and the Boiler, Steam, and Cogeneration (BSC) Component. The BSC Component satisfies the steam demand from the PA and BLD Components. In some industries, the PA Component produces byproducts that are consumed in the BSC Component. For the manufacturing industries, the PA Component is separated into the major production processes or end uses. Petroleum refining (NAICS 32411) is modeled in detail in the Petroleum Market Module of NEMS, and the projected energy consumption is included in the manufacturing total. Projections of refining energy use, lease and plant fuel, and fuels consumed in cogeneration in the oil and gas extraction industry (NAICS 211) are exogenous to the Industrial Demand Module, but endogenous to the NEMS modeling system.

Key assumptions

The NEMS Industrial Demand Module primarily uses a bottom-up process modeling approach. An energy accounting framework traces energy flows from fuels to the industry's output. An important assumption in the development of this system is the use of 2006 baseline Unit Energy Consumption (UEC) estimates based on analysis and interpretations of the Manufacturing Energy Consumption Survey (MECS) 2006 conducted by the Energy Information Administration on a four-year survey cycle [2]. The UECs represent the energy required to produce one unit of the industry's output. The output may be defined in terms of physical units (e.g., tons of steel) or in terms of the dollar value of shipments.

The Industrial Module depicts the manufacturing industries (apart from petroleum refining) with a detailed process flow or end use approach. The dominant process technologies are characterized by a combination of unit energy consumption estimates and "technology possibility curves." The technology possibility curve is an exponential growth trend corresponding to a given average annual rate of change, or technology possibility coefficient (TPC). The TPC defines the assumed average annual rate of energy intensity change of a process step or an energy end use (e.g., generic heating or cooling). The TPCs for new and existing plants vary by industry, vintage and process. These assumed rates were developed using professional engineering judgments regarding the energy characteristics, year of availability, and rate of market adoption of new process technologies.

Process/assembly component

The PA Component models each major manufacturing production step or end use for the manufacturing industries. The throughput production for each process step is computed, as well as the energy required to produce it. The unit energy coefficient (UEC) is defined as the amount of energy to produce a unit of output; it measures the energy intensity of the process or end use.

The module distinguishes the UECs by three vintages of capital stock. The amount of energy consumption reflects the assumption that new vintage stock will consist of state-of-the-art technologies that are more energy efficient than the average efficiency of the existing capital stock. Consequently, the amount of energy required to produce a unit of output using new capital stock is less than that required by the existing capital stock. The old vintage consists of capital existing in 2006 and surviving after adjusting for assumed retirements each year (Table 6.2). New production capacity is assumed to be added in a given projection year such that sufficient surviving and new capacity is available to meet the level of an industry's output as determined in the NEMS Regional Macroeconomic Module. Middle vintage capital is that which is added after 2006 up through the year prior to the current projection year.

To simulate technological progress and adoption of more efficient energy technologies, the UECs are adjusted each projection year based on the assumed TPC for each step. The TPCs are derived from assumptions about the relative energy intensity (REI) of productive capacity by vintage (new capacity relative to existing stock in a given year) or over time (new or surviving capacity in 2035 relative to the 2006 stock). For example, state-of-the-art additions to steel hot rolling capacity in 2006 are assumed to require only 80 percent as much energy as does the average existing plant, so the REI for new capacity in 2006 is 0.80 (see Table 6.3). Over time, the UECs for new capacity are assumed to improve, and the rate of improvement is given by the TPC. The UECs of the surviving 2006 capital stock are also assumed to decrease over time, but not as rapidly as for new capital stock. For example, with hot rolling, the TPC for new facilities is -0.008, while the TPC for existing facilities is -0.007. Table 6.3 provides more examples, including alternative assumptions used to reflect a more optimistic, "high tech" case.

Table 6.2. Retirement rates

Industry	Retirement Rate (percent)	Industry	Retirement Rate (percent)
Food Products	1.7	Glass and Glass Products	1.3
Pulp and Paper	2.3	Cement	1.2
Iron and Steel		Aluminum	
Blast Furnace and Basic Steel Products	1.5	Metal-Based Durables	1.3
Electric Arc Furnace	1.5	Other Non-intensive Manufacturing	1.3
Coke Oven	2.5		
Other Steel	2.9		

Note: Except for the Blast Furnace and Basic Steel Products Industry, the retirement rate is the same for each process step or end-use within an industry.
Source: Energy Information Administration, Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System, DOE/EIA-M064(2010), (Washington, DC, 2010).

The concepts of REI and TPCs are a means of embodying assumptions regarding new technology adoption in the manufacturing industry and the associated change in energy consumption of capital without characterizing individual technologies in detail. The approach reflects the assumption that industrial plants will change energy consumption as owners replace old equipment with new, sometimes more efficient equipment, add new capacity, add new products, or upgrade their energy management practices. The reasons for the increased efficiency are not likely to be directly attributable to technology choice decisions, changing energy prices, or other factors readily subject to modeling. Instead, the module uses the REI and TPC concepts to characterize intensity trends for bundles of technologies available for major process steps or end use.

There are two exceptions to the general approach in the PA component. The first is for electric motor technology choice implemented for 9 industries to simulate their electric machine drive energy end use. Machine drive electricity consumption in the food industry, the five metal-based durables industries, and the three non-intensive manufacturing industries is calculated by a motor stock model. The beginning stock of motors is modified over the projection horizon as motors are added to accommodate growth in shipments for each sector, as motors are retired and replaced, and as failed motors are rewound. When an old motor fails, an economic choice is made on whether to repair or replace the motor. When a new motor is added, either to accommodate growth or as a replacement, the motor must meet the minimum efficiency standard and a premium efficiency motor is also available. Table 6.4 provides the beginning stock efficiency for seven motor size groups in each of the three industry groups, as well as efficiencies for EPACT minimum and premium motors [3]. As the motor stock changes over the projection horizon, the overall efficiency of the motor population changes as well.

The second exception in the PA component is the Bulk chemicals Sub-model. The methodology is described below.

Bulk chemical industry

The need to analyze the impacts of high energy prices on feedstock use and also to track some of the chemical products that are highly dependent on energy resources, such as ammonia and ethylene, requires a separate sub-model for this important energy user. It is important to note that this is only the PA Component of the bulk chemical energy consumption projections; the BSC and BLD components remain the same for this industry.

Table 6.5 shows the list of the chemical products represented in the model. There are 16 organic, 5 inorganic, 5 resins, and 2 agricultural chemicals, plus four aggregate groups (rest of organic, rest of inorganic, rest of resins, and rest of agricultural chemicals).

The choice of chemicals included in the model is driven by several factors, including relative production volumes, energy intensity, production growth, and/or energy and feedstock consumption. The bulk chemical sub-model has several components that are briefly discussed below.

Chemical production component

This component forecasts chemical production for each chemical in Table 6.5. In the bulk chemical industry, there is significant interplay among basic chemicals, intermediate chemicals, and final chemical products. Experts on the relationships among these chemicals helped develop the methodology used to forecast the production levels of each chemical. The equations that forecast chemical production reflect the relationships between the chemicals. In addition, the relationships between the production levels of the chemicals and the dollar values of output (or shipments) from the chemical industry and other industries that use the chemicals, and other drivers such as gross domestic product (GDP), energy prices, and U.S. population were also considered.

Chemical process component

This component forecasts processes for each chemical in Table 6.5. Besides the level of chemical production, a major driver of energy consumption in the bulk chemical industry is the process used to produce a chemical product. Table 6.6 shows the industrial processes used to produce each chemical represented in the model.

The unit energy requirements of steam, electricity, and fuel for each process listed in Table 6.6 are provided for 14 categories of energy services: process water cooling, pumping, compression, motive force, direct clean heat, indirect heat, indirect drying, concentration, distillation, electrolysis, feedstocks, reforming, fuel from feed [4], and byproduct adjustment [5].

Because the choice of processes is not generally driven just by energy prices, the shares of processes used to produce a chemical are usually estimated outside the model. The exceptions are those chemicals and their processes that use significant amounts of energy feedstocks, such as ethylene, propylene and butadiene. These three basic chemicals are sensitive to energy prices, the model captures the feedstock switching response to changing energy prices. There are other chemicals in which only one production process is used (at an industrial-scale). For these chemicals, the process is assigned a 100 percent share.

As indicated above, three chemicals, ethylene, propylene, and butadiene are modeled with more detail than the other chemicals in the model. More detailed descriptions of the representations of process or feedstock requirement choices for these chemicals are discussed below.

Table 6.3. Coefficients for technology possibility curve for all industrial scenarios

applies to all fuels unless specified

	Existing Facilities					New Facillities			
Industry/Process Unit	Reference REI2035[1]	High Tech REI 2035[1]	Reference TPC%[2]	High Tech TPC%[2]	REI 2006[3]	Reference REI2035[4]	High Tech REI 2035[4]	Reference TPC%[2]	High Tech TPC%[2]
Food Products									
Process Heating	0.883	0.987	-0.426	-0.045	0.900	0.784	0.876	-0.477	-0.094
Process Heating-Steam	0.780	0.974	-0.853	-0.091	0.900	0.682	0.852	-0.953	-0.188
Process Cooling-Electricity	0.855	0.983	-0.540	-0.057	0.850	0.734	0.826	-0.506	-0.100
Process Cooling-Natural Gas	0.883	0.987	-0.426	-0.045	0.900	0.784	0.876	-0.477	-0.094
Other-Electricity	0.900	0.989	-0.364	-0.039	0.915	0.793	0.890	-0.493	-0.097
Other-Natural Gas	0.883	0.987	-0.426	-0.045	0.900	0.784	0.876	-0.477	-0.094
Paper & Allied Products									
Wood Preparation	0.792	0.990	-0.802	-0.033	0.882	0.701	0.987	-0.790	-0.386
Waste Pulping-Electricity	0.936	0.954	-0.228	-0.161	0.936	0.936	0.876	0.000	-0.228
Waste Pulping-Steam	0.876	0.954	-0.456	-0.161	0.936	0.936	0.876	0.000	-0.228
Mechanical Pulping-Electricity	0.800	1.006	-0.767	0.021	0.931	0.622	1.205	-1.380	0.893
Mechanical Pulping-Steam	0.639	1.006	-1.533	0.021	0.931	0.413	1.205	-2.760	0.893
Semi-Chemical-Electricity	0.951	0.993	-0.173	-0.025	0.971	0.930	0.956	-0.149	-0.952
Semi-Chemical-Steam	0.904	0.933	-0.346	-0.025	0.971	0.891	0.956	-0.297	-0.052
Kraft, Sulfite, Misc. Chemicals	0.860	0.930	-0.519	-0.249	0.914	0.810	0.790	-0.415	-0.502
Kraft, Sulfite, Misc Chemicals-Steam	0.739	0.930	-1.037	-0.249	0.914	0.718	0.790	-0.830	-0.502
Bleaching-Electricity	0.780	0.929	-0.853	-0.252	0.878	0.680	0.912	-0.878	0.129
Bleaching-Steam	0.607	0.929	-1.706	-0.252	0.878	0.525	0.912	-1.756	0.129
Paper Making	0.869	0.835	-0.485	-0.621	0.885	0.852	0.592	-0.132	-1.376
Paper Making-Steam	0.976	0.835	-0.969	-0.621	0.885	0.820	0.592	-0.264	-1.376
Glass and Glass Products[5]									
Batch Preparation-Electricity	0.941	1.000	-0.209	0.000	0.882	0.882	0.882	0.000	0.000
Melting/Refining	0.934	0.846	-0.235	-0.576	0.900	0.858	0.601	-0.125	-1.381
Melting/Refining-Steam	0.872	0.846	-0.470	-0.576	0.900	0.837	0.601	-0.250	-1.381
Forming	0.984	0.976	-0.056	-0.085	0.982	0.968	0.933	-0.048	-0.175
Forming-Steam	0.968	0.976	-0.111	-0.085	0.982	0.955	0.933	-0.096	-0.175
Post-Forming	0.978	0.990	-0.078	-0.034	0.968	0.955	0.948	-0.045	-0.069
Post-Forming-Steam	0.955	0.990	-0.157	-0.034	0.968	0.943	0.948	-0.090	-0.069
Cement									
Dry Process	0.885	0.870	-0.420	-0.479	0.885	0.770	0.621	-0.479	-1.216
Wet Process[6]	0.944	0.931	-0.197	-0.245	NA	NA	NA	NA	NA
Wet Process-Steam	0.892	0.851	-0.395	-0.554	NA	NA	NA	NA	NA
Finish Griding-Electricity	0.975	0.851	-0.087	-0.554	0.950	0.950	0.660	0.000	-1.248
Iron and Steel									
Coke Oven[6]	0.935	0.883	-0.233	-0.429	0.902	0.869	0.659	-0.128	-1.076
Coke Oven-Steam	0.873	0.883	-0.467	-0.429	0.902	0.837	0.659	-0.257	-1.076
BF/BOF	0.994	0.951	-0.022	-0.172	0.987	0.987	0.885	0.000	-0.375
BF/BOF-Steam	0.987	0.951	-0.045	-0.172	0.987	0.987	0.865	0.000	-0.375
EAF	0.915	0.904	-0.308	-0.346	0.990	0.830	0.781	-0.606	-0.813
Ingot Casting/Primary Rolling[6]	1.000	1.000	0.000	0.000	NA	NA	NA	NA	NA

Table 6.3. Coefficients for technology possibility curve for all industrial scenarios (cont)
applies to all fuels unless specified

Industry/Process Unit	Existing Facilities: Reference REI2035[1]	Existing Facilities: High Tech REI 2035[1]	Existing Facilities: Reference TPC%[2]	Existing Facilities: High Tech TPC%[2]	REI 2006[3]	New Facilities: Reference REI2035[4]	New Facilities: High Tech REI 2035[4]	New Facilities: Reference TPC%[2]	New Facilities: High Tech TPC%[2]
Continuous Casting	1.000	1.000	0.000	0.000	1.000	0.000	1.000	0.000	0.000
Hot Rolling[7]	0.816	0.905	-0.699	-0.344	0.800	0.633	0.602	-0.804	-0.978
Hot Rolling-Steam[7]	0.665	0.905	-1.397	-0.344	0.800	0.500	0.602	-1.608	-0.978
Coal Rolling[7]	0.717	0.948	-1.141	-1.183	0.924	0.433	0.854	-2.580	-0.273
Cold Rolling-Steam[7]	0.512	0.948	-2.281	-1.183	0.924	0.199	0.854	-5.160	-0.273
Aluminum									
Alumina Refining	0.927	0.982	-0.262	-0.063	0.900	0.854	0.865	-0.182	-0.138
Alumnina Refining-Steam	0.859	0.871	-0.524	-0.476	0.900	0.809	0.635	-0.365	-1.198
Primary Smelting	0.890	0.871	-0.401	-0.476	0.950	0.780	0.670	-0.678	-1.198
Primary Smelting-Steam	0.792	0.871	-0.802	-0.476	0.950	0.640	0.670	-1.355	-1.198
Secondary	0.868	0.933	-0.487	-0.238	0.850	0.736	0.716	-0.495	-0.590
Semi-fabrication, Steel	0.893	0.807	-0.389	-0.735	0.900	0.736	0.512	-0.466	-1.927
Semi-Fabrication, Other	0.918	0.874	0.295	0.465	0.950	0.836	0.688	-0.440	-1.109
Metal-Based Durables									
Fabricated Metals									
Process Heating	0.689	0.651	-1.427	-1.468	0.675	0.400	0.337	-1.784	-2.370
Process Cooling-Electricity	0.720	0.587	-1.127	-1.820	0.638	0.365	0.307	-1.903	-2.493
Process Cooling-Natural Gas	0.720	0.651	-1.127	-1.468	0.675	0.413	0.337	-1.679	-2.370
Other	0.720	0.651	-1.127	-1.468	0.675	0.413	0.337	-1.679	-2.370
Other-Electricity	0.720	0.689	-1.127	-1.274	0.686	0.401	0.335	-1.834	-2.439
Machinery									
Process Heating	0.659	0.651	-1.427	-1.468	0.675	0.307	0.236	-2.676	-3.555
Process Cooling-Electricity	0.720	0.587	-1.127	-1.820	0.638	0.275	0.211	-2.855	-3.740
Process Cooling-Natural Gas	0.720	0.651	-1.127	-1.468	0.675	0.322	0.236	-2.519	-3.555
Other	0.720	0.651	-1.127	-1.468	0.675	0.322	0.236	-2.519	-3.555
Other-Electricity	0.720	0.689	-1.127	-1.274	0.686	0.306	0.233	-2.751	-3.658
Computers and Electronics									
Process Heating	0.758	0.752	-0.952	-0.979	0.720	0.555	0.510	-0.892	-1.185
Process Cooling-Electricity	0.804	0.702	-0.751	-1.213	0.680	0.515	0.473	-0.952	-1.247
Process Cooling-Natural Gas	0.804	0.752	-0.751	-0.979	0.720	0.564	0.510	-0.840	-1.185
Other	0.804	0.752	-0.751	-0.979	0.720	0.564	0.510	-0.840	-1.185
Other-Electricity	0.804	0.781	-0.751	-0.850	0.732	0.560	0.513	-0.917	-1.219
Electrical Equipment									
Process Heating	0.758	0.752	-0.952	0.979	0.720	0.555	0.510	-0.892	-1.185
Process Heating-Steam	NA	NA	-1.502	-1.957	NA	NA	NA	-1.679	-2.370
Process Cooling-Electricity	0.804	0.7092	-0.751	-1.213	0.680	0.515	0.473	-0.892	-1.247
Process Cooling-Natural Gas	0.804	0.752	-0.751	-0.979	0.720	0.564	0.510	-0.840	-1.185
Other	0.804	0.752	-0.751	-0.979	0.720	0.564	0.510	-0.840	-1.185
Other-Electricity	0.804	0.781	-0.751	-0.850	0.732	0.560	0.513	-0.917	-1.219

Table 6.3. Coefficients for Technology Possibility Curve for all Industrial Scenarios (cont)
applies to all fuels unless specified

	Existing Facilities					New Facillities			
Industry/Process Unit	Reference REI2035[1]	High Tech REI 2035[1]	Reference TPC%[2]	High Tech TPC%[2]	REI 2006[3]	Reference REI2035[4]	High Tech REI 2035[4]	Reference TPC%[2]	High Tech TPC%[2]
Transportation Equipment									
Processing Heating	0.824	0.819	-0.666	-0.685	0.765	0.622	0.580	-0.714	-0.948
Processing Heating-Steam	0.736	0.670	-1.052	-1.370	0.765	0.517	0.439	-1.343	-1.896
Process Cooling-Electricity	0.858	0.781	-0.526	-0.849	0.723	0.579	0.540	-0.761	-0.997
Process Cooling-Natural Gas	0.858	0.819	-0.526	-0.685	0.765	0.629	0.580	-0.672	-0.948
Other	0.858	0.819	-0.526	-0.685	0.765	0.629	0.580	-0.672	-0.948
Other-Electricity	0.858	0.841	-0.526	-0.595	0.778	0.628	0.585	-0.734	-0.975
Other Non-Intensive Manufacturing									
Wood Products									
Process Heating	0.659	0.654	-1.427	-1.452	0.630	0.374	0.315	-1.784	-2.358
Process Heating-Steam	0.516	0.426	-2.253	-2.903	0.630	0.234	0.155	-3.358	-4.716
Process Cooling-Electricity	0.720	0.590	-1.127	-1.604	0.595	0.341	0.287	-1.903	-2.481
Process Cooling-Natural Gas	0.720	0.654	-1.127	-1.452	0.630	0.386	0.315	-1.679	-2.358
Other	0.720	0.690	-1.127	-1.272	0.630	0.386	0.330	-1.679	-2.209
Other-Electricity	0.722	0.879	-1.115	-0.443	0.641	0.373	0.318	-1.845	-2.388
Plastic Products									
Process Heating	0.758	0.754	-0.952	-0.968	0.675	0.521	0.479	-0.892	-1.179
Process Heating-Steam	0.645	0.567	-1.502	-1.936	0.675	0.413	0.338	-1.679	-2.358
Process Cooling-Electricity	0.804	0.704	-0.751	-1.203	0.638	0.483	0.444	-0.952	-1.241
Process Cooling-Natural Gas	0.804	0.754	-0.751	-0.968	0.675	0.529	0.479	-0.840	-1.179
Other	0.804	0.781	-0.751	-0.848	0.675	0.529	0.489	-0.840	-1.104
Other-Electricity	0.805	0.918	-0.743	-0.295	0.686	0.525	0.484	-0.922	-1.194
Balance of Manufacturing									
Process Heating	0.812	0.810	-0.714	-0.726	0.675	0.548	0.513	-0.714	-0.943
Process Heating-Steam	0.917	0.894	-0.300	-0.387	0.900	0.781	0.737	-0.490	-0.688
Process Cooling-Electricity	0.849	0.769	-0.563	-0.902	0.638	0.511	0.477	-0.761	-0.992
Process Cooling-Natural Gas	NA	NA	-0.563	-0.726	NA	NA	NA	-0.672	-0.943
Other Natural Gas	0.849	0.831	-0.563	-0.636	0.675	0.522	-0.672	-0.672	-0.883

1REI 2035 Existing Facilities = Ratio of 2035 energy intensity to average 2006 energy intensity for existing facilities.
2TPC = annual rate of change between 2006 and 2035.
3REI 2006 New Facilities = For new facilities, the ratio of state-of-the-art energy intensity to average 2006 energy intensity for existing facilities.
4REI 2035 New Facilities = Ratio of 2035 energy intensity for a new state-of-the-art facility to the average 2006 intensity for existing facilities.
5REI's and TPCs apply to virgin and recycled materials.
6No new plants are likely to be built with these technologies.
7Net shape casting is projected to reduce the energy requirements for hot and cold rolling rather than for the continuous casting step.
NA = Not applicable.
BF = Blast furnace.
BOF = Basic oxygen furnace.
EAF = Electric arc furnace.
Source: U.S. Energy Information Administration, Model Documentation Report, Industrial Sector Demand Module of the National Energy Modeling System, DOE/EIA-M064(2010) (Washington, DC, 2010).

Table 6.4. Cost and performance parameters for industrial motor choice model

Industrial Sector Horsepower Range	Base Stock Efficiency (%)	Premium Efficiency (%)	Premium Cost (2002$)
Food			
1-5 hp	86.7	89.2	601
6 - 20 hp	91.2	92.5	1,338
21 - 50 hp	93.0	93.8	2,585
51 - 100 hp	94.0	95.3	6,290
101 - 200 hp	94.6	95.2	11,430
201 - 500 hp	93.6	95.4	29,991
> 500 hp	94.1	96.2	36,176
Metal-Based Durables[1]			
1-5 hp	86.7	89.2	601
6-20 hp	91.3	92.5	1,338
21-50 hp	93.0	93.9	2,585
51-100 hp	94.0	95.3	6,290
101-200 hp	94.6	95.2	11,430
201-500 hp	93.7	95.4	29,991
>500 hp	94.1	96.2	36,176
Other Non-Intensive Manufacturing[2]			
1-5 hp	86.7	89.2	601
6-20 hp	91.3	92.5	1,338
21-50 hp	93.0	93.9	2,585
51-100 hp	94.0	95.3	6,290
101-200 hp	94.6	95.2	11,430
201-500 hp	93.7	95.4	11,430
>500 hp	94.1	96.2	36,176

[1]The Metal-Based Durables group includes five industries that are modeled separately: Fabricated Metal Products; Machinery; Computer and Electronic Products; Electrical Equipment, Appliances, and Components; and Transportation Equipment.
[2]The Other Non-Intensive Manufacturing group includes three sectors that are modeled separately: Wood Products; Plastics and Rubber Products; and Balance of Manufacturing.
Source: U.S. Energy Information Administration, Model Documentation Report, Industrial Sector Demand Module of the National Energy Modeling System, DOE/EIA-M064(2010) (Washington, DC, 2010).
Note: The efficiencies listed in this table are operating efficiencies based on average part-loads. Because the average part-load is not the same for all industries, the listed efficiencies for the different motor sizes vary across industries.

Table 6.5. Chemical products in the bulk chemical industry model

Organic Chemicals	Inorganic Chemicals	Plastic Resins	Agricultural Chemicals
Ethylene	Acetylene	Polyvinyl Chloride	Ammonia
Propylene	Chlorine	Polyethylene	Phosphoric Acid
Butadiene	Oxygen	Polystyrene	Other Agricultural Chemicals
Acetic Acid	Sulfuric Acid	Styrene-Butadiene-Rubber	
Acrylonitrite	Hydrogen	Vinyl Chloride	
Ethylbenzene	Other Inorganic Chemicals	Other Resins	
Ethylene Dichloride			
Ethylene Glycol			
Ethylene Oxide			
Formaldehyde			
Styrene			
Vinyl Acetate			
Ethanol			
On-Purpose Propylene (and byproduct ethylene)			
Other Organic Chemicals			

Ethylene, propylene, and butadiene feedstock requirements component

This component forecasts feedstock requirements for ethylene, propylene, and butadiene products. The primary feedstocks used to produce these chemicals are natural gas liquids (NGLs) (ethane, propane, butane) and petrochemical feedstocks (gas oil, naphtha) [6]. Biomass is a potential raw material source, but it is assumed that there will be no-biomass-based capacity over the projection period because of economic barriers. The type of feedstock not only determines the source of feedstock but also the energy for heat and power requirements to produce the chemicals. The main approach used to forecast the shares of ethylene, propylene, and butadiene feedstock requirements is the use of linear regression equations relating the feedstock shares with petroleum naphtha prices and NGL prices [7].

Energy consumption component

This component calculates the energy requirements (machine drive, non-machine drive electricity, direct process heat, feedstocks, steam) for each chemical/chemical group in Table 6.5. Unit energy (steam, fuel, electricity) requirements for each of the 14 energy services listed above are assumed to change as energy prices change. The calculated total steam consumption is passed to the BSC Component.

Buildings component

The total buildings energy demand by industry for each region is a function of regional industrial employment and output. Building energy consumption was estimated for building lighting, HVAC (heating, ventilation, and air conditioning), facility support, and on-site transportation. Space heating was further divided to estimate the amount provided by direct combustion of fossil fuels and that provided by steam (Table 6.7). Energy consumption in the BLD Component for an industry is estimated based on regional employment and output growth for that industry using the 2006 MECS as a basis.

Boiler, steam, and cogeneration component

The steam demand and byproducts from the PA and BLD Components are passed to the BSC Component, which applies a heat rate and a fuel share equation (Table 6.8) to the boiler steam requirements to compute the required energy consumption.

The boiler fuel shares apply only to the fuels that are used in boilers for steam-only applications. Fuel shares for the portion of the steam demand associated with combined heat and power (CHP) is assumed fixed. Some fuel switching for the remainder of the boiler fuel use is assumed and is calculated with a logit sharing equation where fuels shares are a function of fuel prices. The equation is calibrated to 2006 so that the 2006 fuel shares are produced for the relative prices that prevailed in 2006.

Table 6.6. Chemical products in the bulk chemical industry model

Chemicals	Manufacturing Processes
A. Organic Chemicals	
Ethylene	Prolysis of ethane, propane, gas oil, naphtha, or butane Biomass to ethylene conversion
Propylene	Pyrolysis of ethane, propane, gas oil, naphtha, or butane
Butadiene	Pyrolysis of ethane, propane, gas oil, naphtha, or butane Catalytic dehydrogenation of butane Catalytic dehydrogenation of n-butan
Acetic Acid	N-butane oxidation Methanol carbonylation Biomass Fermentation
Acrylontrile	Ammoxidation of propylene
Ethylbenzene	Alkylation of benzene with ethylene
Ethylene Dichloride	Catalytic oxychlorination of ethylene direct Catalytic chlorination of ethylene
Ethylene Glycol	Hydration of ethylene oxide Biiomass to EG conversion
Ethylene Oxide	Catalytic oxidation of ethylene
Formaldehyde	Catalytic oxidation of methanol (silver) Catalytic oxidation of methanol (mixed) Dehydrogenation of methanol (silver)
Methanol	LP cat of reform natural gas LP synthesis from partial oxidation of resid HP cat conversion of synthesis gas Coal to methanol conversion Biomass to methanol conversion
Styrene	Catalytic dehydrogenation of ethylbenzene Ethylbenzene hydroperoxidation
Vinyl Acetate	Catalytic oxyacetylation of ethylene Acetic acid and acetylene
Ethanol (excludes wet milling)	Dry milling Ethylene hydration
On-Purpose Propylene (and byproduct ethylene)	Generic Process - On purpose Propylene
Other Organic Chemicals	Generic Process - Organic
B. Inorganic Chemicals	
Acetylene	Partial oxidation of methane Crude oil submerged flame
Chlorine	Diaphragm cell Mercury cell Membrane cell
Oxygen	Air liquefaction/Refrigeration
Sulfuric Acid	Contact process
Hydrogen	Steam methane reforming - natural gas Coal gasification Biomass gasification Electrolysis

Table 6.6. Chemical products in the bulk chemical industry model (cont.)

Chemicals	Manufacturing Processes
B. Inorganic Chemicals	
Acetylene	Partial oxidation of methane Crude oil submerged flame
Chlorine	Diaphragm cell Mercury cell Membrane cell
Oxygen	Air liquefaction/Refrigeration
Sulfuric Acid	Contact process
Hydrogen	Steam methane reforming - natural gas Coal gasification Biomass gasification Electrolysis
Other Inorganic Chemicals	Generic Process - Inorganic
C. Plastic Resins	
Polyvinyl Chloride	Suspension process
Polyethylene	Slurry process Solution process Emulsification process
Polystyrene	Mass Polymerization of Styrene
Styrene-Butadiene-Rubber	Emulsification process Solution-polymerized Solid rubber
Vinyl Chloride	Pyrolysis of Ethylene dichloride
Other Plastic Resins	Generic Process - Plastic Resins
D. Agriculture Chemicals	
Ammonia	Catalytic synthesis of methane Partial oxidation of coal Coal gasification Petroleum coke gasification
Phosphoric Acid	Wet process Electric furnace process
Other Agricultural Chemicals	Generic Process - Agricultural chemicals

The byproduct fuels, production of which is estimated in the PA Component, are assumed to be consumed without regard to price, independent of purchased fuels. The boiler fuel share equations and calculations are based on the 2006 MECS.

Combined heat and power

CHP plants, which are designed to produce both electricity and useful heat, have been used in the industrial sector for many years. The CHP estimates in the module are based on the assumption that the historical relationship between industrial steam demand and CHP will continue in the future, and that the rate of additional CHP penetration will depend on the economics of retrofitting CHP plants to replace steam generated from existing non-CHP boilers. The technical potential for CHP is primarily based on supplying thermal requirements. Capacity additions are then determined by the interaction of CHP investment payback periods (with the time-value of money included) and market penetration rates for investments with those payback periods. Assumed installed costs for the CHP systems are given in Table 6.9.

Table 6.7. 2006 Building component energy consumption
trillion Btu

Industry	Region	Lighting Electricity Consumption	HVAC Electricity Consumption	HVAC Natural Gas Consumption	HVAC Steam Consumption	Facility Support Total Consumption	Onsite Transportation Total Consumption
			Building Use and Energy Source				
Food Products	1	1.5	1.7	1.7	1.2	1.0	0.6
	2	8.3	9.1	14.9	5.3	7.0	1.2
	3	6.5	7.1	8.7	6.0	4.6	1.3
	4	3.5	3.9	7.0	4.8	3.3	1.5
Paper & Alllied Products	1	1.6	1.8	2.6	0.0	0.7	1.8
	2	3.7	4.1	2.9	0.0	1.2	1.3
	3	8.7	9.8	9.5	0.0	3.0	4.2
	4	3.9	4.4	2.9	0.0	1.3	1.8
Bulk Chemicals	1	1.0	1.3	1.6	0.0	1.1	1.9
	2	2.9	3.8	4.2	0.0	3.1	4.1
	3	11.1	14.5	11.5	0.0	10.6	6.8
	4	1.1	1.5	1.7	0.0	1.3	2.0
Glass & Glass Products	1	0.4	0.3	3.4	0.0	2.2	2.5
	2	1.2	1.0	5.8	0.0	2.7	2.8
	3	1.1	0.9	6.1	0.0	2.7	2.7
	4	0.3	0.3	3.1	0.0	2.1	2.5
Cement	1	0.2	0.4	0.7	0.0	0.6	0.7
	2	0.5	0.8	0.7	0.0	1.0	1.4
	3	0.7	1.1	0.8	0.0	1.1	2.3
	4	0.5	0.7	0.6	0.0	0.9	1.4
Iron and Steel	1	1.0	0.8	2.6	0.0	0.8	0.7
	2	2.6	2.0	8.8	0.0	1.5	1.9
	3	2.7	2.0	3.6	0.0	1.1	1.2
	4	0.4	0.3	1.3	0.0	0.6	0.7
Aluminum	1	0.4	0.2	0.6	0.0	0.4	0.2
	2	0.5	0.3	1.1	0.0	0.5	0.2
	3	1.9	1.2	2.8	0.0	1.6	0.7
	4	0.3	0.2	0.4	0.0	0.3	0.2
Metal-Based Durables							
Fabricated Metal Products	1	1.8	1.8	4.7	4.0	0.7	0.4
	2	5.9	5.9	18.7	15.9	2.5	2.0
	3	4.7	4.7	11.9	10.0	1.9	2.3
	4	1.8	1.8	2.5	2.1	0.6	0.5
Machinery	1	2.5	1.8	4.7	4.0	0.7	0.4
	2	9.5	5.9	18.7	15.9	2.5	2.0
	3	3.7	4.7	11.9	10.0	1.9	2.3
	4	0.7	1.8	2.5	2.1	0.6	0.5

Table 6.7. 2006 Building component energy consumption (cont.)
trillion Btu

		Building Use and Energy Source					
Industry	Region	Lighting Electricity Consumption	HVAC Electricity Consumption	HVAC Natural Gas Consumption	HVAC Steam Consumption	Facility Support Total Consumption	Onsite Transportation Total Consumption
Computers & Electronic Products	1	2.0	4.8	4.4	3.9	1.7	0.6
	2	1.7	4.0	4.6	4.0	1.5	0.6
	3	3.1	7.3	4.2	3.6	2.3	0.6
	4	4.3	10.2	7.4	6.5	3.0	0.6
Electrical Equipment	1	3.5	4.5	11.6	0.9	1.3	0.4
	2	15.2	19.9	56.2	4.2	5.8	2.1
	3	8.0	10.4	14.1	1.1	2.6	1.2
	4	2.7	3.5	6.9	0.4	0.9	0.5
Transportation Equipment	1	0.6	0.7	0.7	0.5	0.2	0.3
	2	1.7	2.1	2.4	1.9	0.8	0.5
	3	2.5	3.0	4.8	3.7	1.2	0.6
	4	0.2	0.3	0.5	0.4	0.1	0.3
Other Non-Intensive Manufacturing Wood Products	1	0.5	0.3	0.5	0.9	0.1	0.9
	2	2.1	1.5	3.0	5.8	0.6	4.2
	3	2.3	2.3	1.9	3.7	0.7	5.0
	4	1.4	1.0	1.7	3.3	0.4	4.2
Plastic Products	1	2.0	2.5	4.3	0.0	1.2	1.3
	2	7.0	8.7	9.6	0.0	3.1	1.0
	3	5.9	7.4	11.2	0.0	2.9	1.0
	4	1.1	1.4	0.8	0.0	0.5	0.3
Balance of Manufacturing	1	5.7	8.8	14.9	0.0	2.3	1.9
	2	16.7	25.8	23.1	0.0	6.1	1.3
	3	21.4	33.0	43.7	0.0	8.3	2.1
	4	4.0	6.1	11.1	0.0	1.7	0.9

HVAC = Heating, Ventilation, Air Conditioning
Source: U.S. Energy Information Administration, Model Documentation Report, Industrial Sector Demand Module of the National Energy Modeling System, DOE/EIA-M064(2010) (Washington, DC 2010).

Table 6.8. 2006 Boiler fuel component and logit parameter
trillion Btu

	Region	Alpha	Natural Gas	Coal	Oil	Renewables
Food Products	1	-2.0	19	0	4	1
	2	-2.0	168	109	12	22
	3	-2.0	96	11	12	52
	4	-2.0	76	14	4	4
Paper & Allied Products	1	-2.0	41	40	16	80
	2	-2.0	48	60	12	90
	3	-2.0	159	91	64	998
	4	-2.0	53	13	4	97
Bulk Chemicals	1	-2.0	13	0	56	0
	2	-2.0	97	37	18	0
	3	-2.0	605	31	384	0
	4	-2.0	20	21	6	0
Glass & Glass Products	1	-2.0	2	0	3	10
	2	-2.0	6	0	3	1
	3	-2.0	6	0	3	2
	4	-2.0	1	0	3	1
Cement	1	-2.0	0	0	1	1
	2	-2.0	1	0	1	5
	3	-2.0	0	0	1	3
	4	-2.0	0	0	1	3
Iron & Steel	1	-2.0	4	6	20	0
	2	-2.0	16	1	66	0
	3	-2.0	6	0	7	0
	4	-2.0	1	0	1	0
Aluminum	1	-2.0	2	0	0	0
	2	-2.0	4	0	0	0
	3	-2.0	11	0	0	0
	4	-2.0	1	0	0	0
Metal-Based Durables						
Fabricated Metal Products	1	-2.0	4	0	1	0
	2	-2.0	5	0	1	0
	3	-2.0	4	0	1	0
	4	-2.0	8	0	1	1
Machinery						
	1	-2.0	3	0	1	0
	2	-2.0	12	1	0	1
	3	-2.0	5	0	0	0
	4	-2.0	1	0	0	0
Computers & electronic Products	1	-2.0	4	0	1	0
	2	-2.0	5	0	1	0
	3	-2.0	4	0	1	0
	4	-2.0	8	0	1	1
Electrical Equipment	1	-2.0	6	8	3	7
	2	-2.0	27	-3	1	5
	3	-2.0	7	1	3	4
	4	-2.0	3	0	0	0

Table 6.8. 2006 Boiler fuel component and logit parameter (cont.)
trillion Btu

	Region	Alpha	Natural Gas	Coal	Oil	Renewables
Transportation Equipment	1	-2.0	1	0	0	0
	2	-2.0	2	0	0	0
	3	-2.0	4	0	0	0
	4	-2.0	0	0	0	0
Other Non-Intensive Manufacturing Wood Products	1	-2.0	2	0	0	11
	2	-2.0	12	1	1	40
	3	-2.0	7	0	1	123
	4	-2.0	5	0	2	48
Plastic Products	1	-2.0	10	0	2	0
	2	-2.0	23	0	0	0
	3	-2.0	25	10	6	0
	4	-2.0	2	0	0	0
Balance of Manufacturing	1	-2.0	41	-11	18	1
	2	-2.0	64	51	28	2
	3	-2.0	121	58	31	22
	4	-2.0	31	8	15	0

Alpha: User-specified.
Source: U.S. Energy Information Administration, Model Documentation Report, Industrial Sector Demand Module of the National Energy Modeling System, DOE/EIA-M064(2010) (Washington, DC 2010).

Table 6.9. Cost characteristics of industrial CHP systems

System	Size Kilowatts (KW)	Reference 2010	Installed Cost ($2005 per KWh)[1] Reference 2035	High Tech 2035
Engine	100	1440	576	535
	300	1260	396	354
Gas turbine	3000	1719	1496	1450
	5000	1152	1023	1006
	10000	982	869	869
	25000	987	860	860
	40000	875	830	830
Combined cycle	100000	723	684	668

[1]Costs are given in 2005 dollars in original source document.
Source: U.S. Energy Information Administration, Model Documentation Report, Industrial Sector Demand Module of the National Energy Modeling System, DOE/EIA-M064(2010) (Washington, DC 2010).

Legislation and regulations

Energy Improvement and Extension Act of 2008

Under EIEA2008 Title I, "Energy Production Incentives," Section 103 provides an Investment Tax Credit (ITC) for qualifying Combined Heat and Power (CHP) systems placed in service before January 1, 2017. Systems with up to 15 megawatts of electrical capacity qualify for an ITC up to 10 percent of the installed cost. For systems between 15 and 50 megawatts, the percentage tax credit declines linearly with the capacity, from 10 percent to 3 percent. To qualify, systems must exceed 60-percent fuel efficiency, with a minimum of 20 percent each for useful thermal and electrical energy produced. The provision was modeled in *AEO2011* by adjusting the assumed capital cost of industrial CHP systems to reflect the applicable credit.

The Energy Independence and Security Act of 2007

Under EISA2007, the motor efficiency standards established under the Energy Policy Act of 1992 (EPACT) are superseded for purchases made after 2011. Section 313 of EISA2007 increases or creates minimum efficiency standards for newly manufactured, general purpose electric motors. The efficiency standards are raised for general purpose, integral-horsepower induction motors with the exception of fire pump motors. Minimum standards were created for seven types of poly-phase, integral-horsepower induction motors and NEMA design "B" motors (201-500 horsepower) that were not previously covered by EPACT standards. The industrial module's motor efficiency assumptions reflect the EISA2007 efficiency standards for new motors added after 2011.

Energy Policy Act of 1992 (EPACT)

EPACT contains several implications for the industrial module. These implications concern efficiency standards for boilers, furnaces, and electric motors. The industrial module uses heat rates of 1.25 (80 percent efficiency) and 1.22 (82 percent efficiency) for gas and oil burners, respectively. These efficiencies meet the EPACT standards. EPACT mandates minimum efficiencies for all motors up to 200 horsepower purchased after 1998. The choices offered in the motor efficiency assumptions are all at least as efficient as the EPACT minimums.

Clean Air Act Amendments of 1990 (CAAA90)

The CAAA90 contains numerous provisions that affect industrial facilities. Three major categories of such provisions are as follows: process emissions, emissions related to hazardous or toxic substances, and SO2 emissions.

Process emissions requirements were specified for numerous industries and/or activities (40 CFR 60). Similarly, 40 CFR 63 requires limitations on almost 200 specific hazardous or toxic substances. These specific requirements are not explicitly represented in the NEMS industrial model because they are not directly related to energy consumption projections.

Section 406 of the CAAA90 requires the Environmental Protection Agency (EPA) to regulate industrial SO2 emissions at such time that total industrial SO2 emissions exceed 5.6 million tons per year (42 USC 7651). Since industrial coal use, the main source of SO2 emissions, has been declining, EPA does not anticipate that specific industrial SO2 regulations will be required (Environmental Protection Agency, National Air Pollutant Emission Trends: 1990-1998, EPA-454/R-00-002, March 2000, Chapter 4). Further, since industrial coal use is not projected to increase, the industrial cap is not expected be a factor in industrial energy consumption projections. (Emissions due to coal-to-liquids CHP plants are included with the electric power sector because they are subject to the separate emission limits of large electricity generating plants.)

Industrial alternative cases

Technology cases

The High Technology case assumes earlier availability, lower costs, and higher efficiency of more advanced equipment, based on engineering judgments and research compiled by Focis Associates in a 2005 study for EIA (Tables 6.3 and 6.9) [8]. The High Technology case also assumes that the rate at which biomass byproducts will be recovered from industrial processes increases from 0.4 percent per year to 0.7 percent per year. The availability of additional biomass leads to an increase in biomass-based cogeneration. Changes in aggregate energy intensity can result both from changing equipment and production efficiency and from changes in the composition of industrial output. Since the composition of industrial output remains the same as in the Reference case, delivered energy intensity declines by 1.1 percent annually compared with the Reference case, in which delivered energy intensity is projected to decline 1.0 percent annually.

The 2010 Technology case holds the energy efficiency of plant and equipment constant at the 2010 level over the projection period. Delivered energy intensity for this case declines by 0.7 percent annually. Both technology cases were run with only the Industrial Demand Module rather than as a fully integrated NEMS run, (i.e., the other demand models and the supply models of NEMS were not executed). Consequently, no potential feedback effects from energy market interactions were captured.

AEO2011 also includes an Integrated High Technology case, which combines the High Technology case of the four end-use demand sectors, the electricity Low Fossil Technology Cost case, the Low Nuclear Cost case, and the Low Renewable Technology Cost case.

The Low Renewable Technology Cost case assumes that the rate at which biomass byproducts will be recovered from industrial processes increases to 1.3 percent per year. The availability of additional biomass leads to an increase in biomass-based CHP.

Notes and sources

[1] U.S. Energy Information Administration, State Energy Data System, based on energy consumption by state through 2008, as downloaded in June, 2010, from www.eia.doe.gov/emeu/states/_seds.html.

[2] U. S. Energy Information Administration, Manufacturing Energy Consumption Survey, website www.eia.doe.gov/emeu/mecs/

[3] U.S., Department of Energy(2007). Motor Master+ 4.0 software database; available online: http://www1.eere.energy.gov/industry/bestpractices/software.html#mm.

[4] Fuel from Feed represents the heat (essentially fuel) from the oxidation of excess feedstocks.

[5] Byproduct adjustment represents recoverable byproduct heat.

[6] In NEMS, NGLs are reported as Liquefied Petroleum Gas (LPG).

[7] Proprietary data from Petral Consluting Company of historical feedstocks in the U.S. petrochemical industry was used; feedstock was grouped into "light" (ethane, propane originating from gas processing plants) and "heavy" (gasoil and naphtha from petroleum refineries)

[8] U.S. Energy Information Administration, Industrial Technology and Data Analysis Supporting the NEMS Industrial Model (Focis Associates, October 2005).

Transportation Demand

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The NEMS Transportation Demand Module estimates transportation energy consumption across the nine Census Divisions (see Figure 5) and over ten fuel types. Each fuel type is modeled according to fuel-specific technology attributes applicable by transportation mode. Total transportation energy consumption is the sum of energy use in eight transport modes: light-duty vehicles (cars and light trucks), commercial light trucks (8,501-10,000 lbs gross vehicle weight), freight trucks (>10,000 lbs gross vehicle weight), buses, freight and passenger aircraft, freight and passenger rail, freight shipping, and miscellaneous transport such as recreational boating. Light-duty vehicle fuel consumption is further subdivided into personal usage and commercial fleet consumption.

Key assumptions

Light-duty vehicle assumptions

The light-duty vehicle Manufacturers echnology Choice Model (MTCM) includes 63 fuel savingtechnologies with data specific to cars and light trucks (Tables 7.1 and 7.2) including incremental fueleconomy improvement, incremental cost, first year of introduction, and fractional horsepower change.

The vehicle sales share module holds the share of vehicle sales by manufacturers constant within a vehicle size class at 2008 levels based on National Highway Traffic and Safety Administration (NHTSA) data [1]. Environmentall Protection Agency (EPA) size class sales shares are projected as a function of income per capita, fuel prices, and average predicted vehicle prices based on endogenous calculations within the MTCM [2] .

The MTCM utiizes 63 new technologies for each size class and manufacturer based on the cost-effectiveness of each technology and an initial availability year. The discounted stream of fuel savings is compared to the marginal cost of each technology. The fuel economy module assumes the following:

- The economic effectiveness of all fuel technologies are evaluated on a varying basis to meet a strict CAFE standard.
- Fuel economy standards reflect current law through model year 2016, according to NHTSA model year 2011 final rulemaking and joint EPA and NHTSA rulemaking for 2012 through 2016. For model years 2017 through 2020, the standards reflect EIA assumed increases that ensure a light vehicle combined fuel economy of 35 mpg is achieved by model 2020. For model years 2021 though 2030, fuel economy standards are held constant at model year 2020 levels with fuel economy improvements still possible based on an economic cost benefit analysis only.
- Expected future fuel prices are calculated based on an extrapolation of the growth rate between a five year moving average of fuel price 3 years and 4 years prior to the present year. This assumption is founded upon an assumed lead time of 3 to 4 years to significantly modify the vehicles offered by a manufacturer.

Table 7.1. Standard technology matrix for cars[1]

	Fuel Efficiency Change %	Incremental Cost (2000$)	Incremental Cost ($/Unit Wt.)	Absolute Incremental Weight (Lbs.)	Per Unit Incremental Weight (Lbs./Unit Wt.)	Introduc-tion Year	Horse-power Change%
Unit Body Construction	4	100	0	0	-6	1980	0
Material Substitution II	3.3	0	0.4	0	-5	1990	0
Material Substitution III	6.6	0	0.6	0	-10	1998	0
Material Substitution IV	9.9	0	0.9	0	-15	2006	0
Material Substitution V	13.2	0	1.2	0	-20	2014	0
Drag Reduction II	1.5	16	0	0	0	1988	0
Drag Reduction III	3.0	32	0	0	0.2	1992	0
Drag Reduction IV	4.2	45	0	0	0.5	2000	0
Drag Reduction V	5.0	53.5	0	0	1	2010	0
Roll-Over Technology	-1.5	100	0	0	2.2	2004	0
Side Impact Technology	-1.5	100	0	0	2.2	2004	0
Adv Low Loss Torque Converter	2	25	0	0	0	1999	0
Early Torque Converter Lockup	0.5	25.6	0	0	0	2002	0
Aggressive Shift Logic	1.5	30.5	0	0	0	1999	0
4-Speed Automatic	4.5	285	0	10	0	1980	0
5-Speed Automatic	2.5	106.5	0	20	0	1995	0
6-Speed Automatic	2.9	259	0	30	0	2003	0
6-Speed Manual	0.5	91.4	0	20	0	1995	0
CVT	5.0	240.5	0	-25	0	1998	0
Automated Manual Trans	7.3	138.6	0	0	0	2004	0
Roller Cam	2	16	0	0	0	1980	0
OHC/AdvOHV-4 Cylinder	2.0	99	0	0	0	1980	2.5
OHC/AdvOHV-6 Cylinder	2.0	115.7	0	0	0	1987	2.5
OHC/AdvOHV-8 Cylinder	2.0	132.3	0	0	0	1986	2.5
4-Valve/4-Cylinder	8	205	0	10	0	1988	4.25
4-Valve/6-Cylinder	8	280	0	15	0	1992	4.25
4 Valve/8-Cylinder	8	320	0	20	0	1994	4.25
5 Valve/6-Cylinder	8	300	0	18	0	1998	5
VVT-4 Cylinder	2.0	48.9	0	10	0	1994	1.25
VVT-6 Cylinder	2.0	97.8	0	20	0	1993	1.25
VVT-8 Cylinder	2.0	97.8	0	20	0	1993	1.25
VVL-4 Cylinder	2.0	162.2	0	25	0	1997	2.5
VVL-6 Cylinder	2.0	245.4	0	40	0	2000	2.5
VVL-8 Cylinder	2.0	317.5	0	50	0	2000	2.5
Camless Valve Actuation-4cyl	13.6	400.9	0	35	0	2020	3.25
Camless Valve Actuation-6cyl	13.6	561.3	0	55	0	2020	3.25
Camless Valve Actuation-8cyl	13.6	721.6	0	75	0	2020	3.25
Cylinder Deactivation	5.3	152.3	0	10	0	2004	0
Turbocharging/Supercharging	6.3	324.7	0	-100	0	1980	3.75
Engine Friction Reduction I	2.3	54	0	0	0	1992	0.75
Engine Friction Reduction II	2.8	60.9	0	0	0	2000	1.25
Engine Friction Reduction III	4.0	138.7	0	0	0	2008	1.75
Engine Friction Reduction IV	6.5	177	0	0	0	2016	2.25
Stoichiometric GDI/4-Cylinder	2.4	293.8	0	20	0	2006	2.5
Stoichiometric GDI/6-Cylinder	2.4	377.6	0	30	0	2006	2.5
Lean Burn GDI	10.0	640.5	0	20	0	2020	0
5W-30 Engine Oil	0.5	4.0	0	0	0	1998	0
5W-20 Engine Oil	2	16.7	0	0	0	2003	0
OW-20 Engine Oil	3.1	150	0	0	0	2030	0
Electric Power Steering	1.5	90.6	0	0	0	2004	0
Improved Alternator	0.3	15	0	0	0	2005	0
Improved Oil/Water Pump	0.5	10	0	0	0	2000	0
Electric Oil/Water Pump	1	93.4	0	0	0	2007	0
Tires II	1.8	15.8	0	-8	0	1995	0
Tires III	2.7	19.9	0	-12	0	2005	0
Tires IV	3.8	22.9	0	-16	0	2015	0
Front Wheel Drive	6	250	0	0	-6	1980	0
Four Wheel Drive Improvements	1.3	93.8	0	0	-1	2000	0
42V-Launch Assist and Regen	7.5	280	0	80	0	2005	-2.5
42V-Engine Off at Idle	6.8	496.6	0	45	0	2005	0
Tier 2 Emissions Technology	-1	120	0	20	0	2006	0
Increased Size/Weight	-0.5	0	0	0	2.55	2006	0
Variable Compression Ratio	4	350	0	25	0	2015	0

[1] Fractional changes refer to the percentage change from the base technology.

Sources: Energy and Environment Analysis, Documentation of Technology included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks (September, 2002). National Research Council, Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards (Copyright 2002).

Table 7.2. Standard technology matrix for light trucks[1]

	Fuel Efficiency Change%	Incremental Cost (2000$)	Incremental Cost ($/UnitWt.)	Absolute Incremental Weight (Lbs.)	Per Unit Incremental Weight (Lbs./ UnitWt.)	Introduc-tion Year	Horse-power Change%
Unit Body Construction	4	100	0	0	-6	1980	0
Material Substitution II	3.3	0	0.4	0	-5	1994	0
Material Substitution III	6.6	0	0.6	0	-10	2002	0
Material Substitution IV	9.9	0	0.9	0	-15	2010	0
Material Substitution V	13.2	0	1.2	0	-20	2018	0
Drag Reduction II	2.0	32	0	0	0	1992	0
Drag Reduction III	4.1	57	0	0	0.2	1998	0
Drag Reduction IV	6.4	89	0	0	0.5	2006	0
Drag Reduction V	7.8	109	0	0	1	2014	0
Roll-Over Technology	-1.5	100	0	0	2.2	2006	0
Side Impact Technology	-1.5	100	0	0	2.2	2006	0
Adv Low Loss Torque Converter	2	25	0	0	0	2005	0
Early Torque Converter Lockup	0.5	25.6	0	0	0	2003	0
Aggressive Shift Logic	1.5	30.5	0	0	0	1999	0
4-Speed Automatic	4.5	285	0	10	0	1980	0
5-Speed Automatic	2.5	106.5	0	20	0	1995	0
6-Speed Automatic	2.9	259	0	30	0	2003	0
6-Speed Manual	0.5	91.4	0	20	0	1995	0
CVT	7.0	138.6	0	-25	0	1998	0
Automated Manual Trans	3.4	157.5	0	0	0	2004	0
Roller Cam	2	16	0	0	0	1985	0
OHC/AdvOHV-4 Cylinder	2.0	99	0	0	0	1980	2.5
OHC/AdvOHV-6 Cylinder	2.0	115.7	0	0	0	1990	2.5
OHC/AdvOHV-8 Cylinder	2.0	132.3	0	0	0	1990	2.5
4-Valve/4-Cylinder	7	205	0	10	0	1998	4.25
4-Valve/6-Cylinder	7	280	0	15	0	2000	4.25
4 Valve/8-Cylinder	7	320	0	20	0	2000	4.25
5 Valve/6-Cylinder	7	300	0	18	0	2010	5
VVT-4 Cylinder	2.0	48.9	0	10	0	1998	1.25
VVT-6 Cylinder	2.0	97.8	0	20	0	1997	1.25
VVT-8 Cylinder	2.0	97.8	0	20	0	1997	1.25
VVL-4 Cylinder	2.0	161.2	0	25	0	2002	2.5
VVL-6 Cylinder	2.0	245.4	0	40	0	2001	2.5
VVL-8 Cylinder	2.0	317.5	0	50	0	2006	2.5
Camless Valve Actuation-4cyl	13.6	400.9	0	35	0	2020	3.25
Camless Valve Actuation-6cyl	13.6	561.3	0	55	0	2020	3.25
Camless Valve Actuation-8cyl	13.6	721.6	0	75	0	2020	3.25
Cylinder Deactivation	5.3	152.3	0	10	0	2004	0
Turbocharging/Supercharging	6.3	481.3	0	-100	0	1987	3.75
Engine Friction Reduction I	2.5	25	0	0	0	1992	0.75
Engine Friction Reduction II	3.5	63	0	0	0	2000	1.25
Engine Friction Reduction III	5	178.0	0	0	0	2010	1.75
Engine Friction Reduction IV	6.5	177	0	0	0	2016	2.25
Stoichiometric GDI/4-Cylinder	2.4	293.9	0	20	0	2008	2.5
Stoichiometric GDI/6-Cylinder	2.4	377.7	0	30	0	2010	2.5
Lean Burn GDI	10.8	640.5	0	20	0	2010	0
5W-30 Engine Oil	0.5	4.0	0	0	0	1998	0
5W-20 Engine Oil	2	16.7	0	0	0	2003	0
OW-20 Engine Oil	3.1	150	0	0	0	2030	0
Electric Power Steering	1.5	90.2	0	0	0	2005	0
Improved Alternator	0.3	15	0	0	0	2005	0
Improved Oil/Water Pump	0.5	10	0	0	0	2000	0
Electric Oil/Water Pump	1	93.4	0	0	0	2008	0
Tires II	0.0	30	0	-8	0	1995	0
Tires III	1.3	15.4	0	-12	0	2005	0
Tires IV	2.7	19.5	0	-16	0	2015	0
Front Wheel Drive	2	250	0	0	-3	1984	0
Four Wheel Drive Improvements	1.3	93.8	0	0	-1	2000	0
42V-Launch Assist and Regen	7.5	280	0	80	0	2005	2.5
42V-Engine Off at Idle	6.8	434.9	0	45	0	2005	0
Tier 2 Emissions Technology	-1	160	0	20	0	2006	0
Increased Size/Weight	-0.8	0	0	0	3.75	2006	0
Variable Compression Ratio	4	350	0	25	0	2015	0

[1]Fractional changes refer to the percentage change from the base technology.

Sources: Energy and Environment Analysis, Documentation of Technology included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks (September, 2002). National Research Council, Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards (Copyright 2002). National Highway Traffic Safety Administration, Corporate Average Fuel Economy for MY 2011-2015 Passenger Cars and Light Trucks (April 2008). U.S. Environmental Protection Agency, Interim Report: New Powertrain Technologies and Their Projected Costs (October 2005).

Degradation factors are used to convert new vehicle tested fuel economy values to "on-road" fuel economy values (Table 7.3). The degradation factors represent adjustments made to tested fuel economy values to account for the difference between fuel economy performance realized in the CAFE test procedure and fuel economy realized under normal driving conditions.

Table 7.3. Car and light truck degradation factors

	2005	2010	2015	2020	2030	2035
Cars	78.3	81.8	82.3	82.8	83.8	83.8
Light Trucks	85.9	84.0	84.0	84.0	84.0	84.0

Source: U.S. Energy Information Administration, *Transportation Sector Model of the National Energy Modeling System*, Model Documentation 2010, DOE/EIA-M070(2007), (Washington, DC, 2010).

Commercial light duty fleet assumptions

The Transportation Demand Module divides commercial light-duty fleets into three types: business, government, and utility. Based on this classification, commercial light-duty fleet vehicles vary in survival rates and duration of in-fleet use before sale for use as personal vehicles (Table 7.4). The average length of time passenger cars are kept before being sold for personal use is 4 years for business use, 5 years for government use, and 6 years for utility use. Of total automobile sales to fleets, 80.6 percent are used in business fleets, 6.5 percent in government fleets, and 12.9 percent in utility fleets. Of total light truck sales to fleets, 59.5 percent are used in business fleets, 3.6 percent in government fleets, and 36.8 percent in utility fleets [3]. Both the automobile and light truck shares by fleet type are held constant from 2005 through 2035. In 2006, 18.1 percent of all automobiles sold and 18.2 percent of all light trucks sold were for fleet use. The share of total automobile and light truck sales to decline over the forecast period based on historic trends.

Table 7.4. 2005 percent of fleet alternative fuel vehicles by fleet type by size class

	Mini	Subcompact	Compact	Midsize	Large	2-Seater
Car						
Business	0.0	10.5	10.7	42.7	36.1	0.0
Government	0.0	2.8	40.0	2.8	54.4	0.0
Utility	0.0	7.9	34.7	12.3	45.1	0.0
	SM Pk	**LG Pk**	**SM Van**	**LG Van**	**SM Util**	**LG Util**
Light Truck						
Business	7.9	35.1	7.9	26.6	5.5	16.8
Government	6.7	50.8	28.4	4.6	1.6	7.8
Utility	8.2	52.1	6.0	32.7	0.3	0.7

Source: CNEAF Alternatives to Traditional Transportation Fuels 2005 (Part II - User and Fuel Data).
http://www.eia.doe.gov/cneaf/alternate/page/aftables/afvtransfuel_II.html #in use

Alternative-fuel shares of fleet vehicle sales by fleet type are held constant at 2005 levels. Size class sales shares of vehicles are also held constant at 2005 levels (Table 7.5) [4]. Individual sales shares of new vehicles purchased by technology type are assumed to remain constant for utility, government, and for business fleets [5] (Table 7.6).

Annual VMT per vehicle by fleet type stays constant over the forecast period based on the Oak Ridge National Laboratory fleet data.

Fleet fuel economy for both conventional and alternative-fuel vehicles is assumed to be the same as the personal new vehicle fuel economy and is subdivided into six EPA size classes for cars and light trucks.

Table 7.5. Commercial fleet size class shares by fleet and vehicle type

percentage

Fleet Type by Size Class	Automobiles	Light Trucks
Business Fleet		
Mini	3.1	2.5
Subcompact	23.4	8.4
Compact	26.6	23.3
Midsize	36.2	8.1
Large	9.9	14.2
2-seater	0.8	43.6
Government Fleet		
Mini	0.2	6.7
Subcompact	4.6	43.6
Compact	20.6	10.4
Midsize	28.6	17.1
Large	46.0	3.8
2-seater	0.0	18.4
Utility Fleet		
Mini	1.5	7.3
Subcompact	12.5	36.7
Compact	10.0	11.8
Midsize	59.2	18.9
Large	16.4	7.2
2-seater	0.4	16.1

Source: Oak Ridge National Laboratory, Fleet Characteristics and Data Issues. Stacy Davis and Lorena Truett, final report prepared for the Department of Energy, Energy Information Administration, Office of Energy Analysis. (Oak Ridge, TN, January 2003).

Table 7.6. Share of new vehicle purchases by fleet type and technology type

percentage

Technology	Business	Government	Utility
Cars			
Gasoline	99.6	79.4	99.7
Ethanol Flex	0.3	19.0	0.1
Electric	0.01	0.01	0.00
CNG Bi-Fuel	0.1	1.4	0.1
LPG Bi-Fuel	0.01	0.00	0.00
CNG	0.1	0.2	0.1
LPG	0.00	0.00	0.00
Light Trucks			
Gasoline	96.1	69.0	99.7
Ethanol Flex	3.4	28.0	0.1
Electric	0.01	0.00	0.00
CNG Bi-Fuel	0.3	2.6	0.1
LPG Bi-Fuel	0.00	0.01	0.01
CNG	0.2	0.4	0.0
LPG	0.00	0.00	0.01

Sources: CNEAF Alternatives to Traditional Transportation Fuels 2005 (part II - User and Fuel Data). http://www.eia.doe.gov/cneaf/alternate/page/aftables/afvtransfuel_II.html #in use.

The light commercial truck model

The Light Commercial Truck Module of the NEMS Transportation Model represents light trucks that have a 8,501 to 10,000 pound gross vehicle weight rating (Class 2B vehicles). These vehicles are assumed to beused primarily for commercial purposes.

The module implements a twenty-year stock model that estimates vehicle stocks, travel, fuel economy, and energy use by vintage. Historic vehicle sales and stock data, which constitute the baseline from which the forecast is made, are taken from a recent Oak Ridge National Laboratory study [6]. The distribution of vehicles by vintage, and vehicle scrappage rates are derived from R.L. Polk company registration data [7],[8]. Vehicle travel by vintage was constructed using vintage distribution curves and estimates of average annual travel by vehicle [9],[10].

The growth in light commercial truck VMT is a function of industrial output for agriculture, mining, construction, total manufacturing, utilities, and personal travel. These groupings were chosen for their correspondence with output measures being forecast by NEMS. The overall growth in VMT reflects a weighted average based on the distribution of total light commercial truck VMT by sector. Forecasted fuel efficiencies are assumed to increase at the same annual growth rate as conventional gasoline light-duty trucks (<8,500 pounds gross vehicle weight).

Consumer vehicle choice assumptions

The Consumer Vehicle Choice Module (CVCM) utilizes a nested multinomial logit (NMNL) model that predicts sales shares based on relevant vehicle and fuel attributes. The nesting structure first predicts the probability of fuel choice for multi-fuel vehicles within a technology set. The second level nesting predicts penetration among similar technologies within a technology set (i.e., gasoline versus diesel hybrids). The third level choice determines market share among the different technology sets [11]. The technology sets include:

- Conventional fuel capable (gasoline, diesel, compressedx natural gas (CNG) and liquefied petroleum gas (LNG), and flex-fuel),
- Hybrid (gasoline and diesel),
- Plug in hybrid (10 mile all-electric range and 40 mile all-electric range)
- Dedicated alternative fuel (CNG and LPG),
- Fuel cell (gasoline, methanol, and hydrogen), and
- Electric battery powered (v-100 mile range and 200 mile range) [12]

The vehicle attributes considered in the choice algorithm include: price, maintenance cost, battery replacement cost, range, multi-fuel capability, home refueling capability, fuel economy, acceleration and luggage space. With the exception of maintenance cost, battery replacement cost, and luggage space, vehicle attributes are determined endogenously [13]. Battery costs for plug-in hybrid electric and all-electric vehicles are based on a production based function over several technology phase periods. The fuel attributes used in market share estimation include availability and price. Vehicle attributes vary by six EPA size classes for cars and light trucks and fuel availability varies by Census division. The NMNL model coefficients were developed to reflect purchase decisions for cars and light trucks separately.

Where applicable, CVCM fuel efficient technology attributes are calculated relative to conventional gasoline miles per gallon. It is assumed that many fuel efficiency improvements in conventional vehicles will be transferred to alternative-fuel vehicles. Specific individual alternative-fuel technological improvements are also dependent upon the CVCM technology type, cost, research and development, and availability over time. Make and model availability estimates are assumed according to a logistic curve based on the initial technology introduction date and current offerings. Coefficients summarizing consumer valuation of vehicle attributes were derived from assumed economic valuation compared to vehicle price elasticities. Initial CVCM vehicle stocks are set according to EIA surveys [14]. A fuel switching algorithm based on the relative fuel prices for alternative fuels compared to gasoline is used to determine the percentage of total VMT represented by alternative fuels in bi-fuel and flex-fuel alcohol vehicles.

Freight truck assumptions

The freight truck module estimates vehicle stocks, travel, fuel efficiency, and energy use for three size classes of trucks: light-medium (Class 3), heavy-medium (Classes 4-6), and heavy (Classes 7-8). Within the size classes, the stock model structure is designed to cover 34 vehicle vintages and to estimate energy use by four fuel types: diesel, gasoline, LPG, and CNG. Fuel consumption estimates are reported regionally (by Census Division) according to the distillate fuel shares from the State Energy Data Report [15]. The technology input data specific to the different types of trucks including the year of introduction, incremental fuel efficiency improvement, and capital cost of introducing the new technologies, are shown in Table 7.7.

Table 7.7. Standard technology matrix for freight trucks

	Medium Light Trucks			Medium Heavy Trucks			Heavy Trucks		
Technology Type	**Introduction Year**	**Capital Cost (2000$)**	**Incr. Fuel Econ. Improvement (%)**	**Introduction Year**	**Capital Cost (2000$)**	**Incr. Fuel Econ. Improvement (%)**	**Introduction Year**	**Capital Cost (2000$)**	**Incr. Fuel Econ. Improvement (%)**
AERO dynamic I: Cab top deflector, sloping hood and cab side flares	N/A	800	2.3	1995	750	2.3	1995	750	1.8
AERO Dynamic II: closing/Covering of gap between tractor and trailer, aero dynamic bumper, underside air baffles, wheel well covers	N/A	N/A	N/A	2004	800	3.6	2005	1500	2.3
AERO Dynamic: III Trailer leading and trailing edge curvatures	N/A	N/A	N/a	2005	400	0.9	2005	500	1.2
Aero Dynamics IV: pneumatic blowing	N/A	N/A	N/A	N/A	N/A	N/A	2010	2500	4.5
Tires I: radials	1995	40	1.8	1995	180	1.8	1995	300	1.4
Tires II: low rolling resistance	2004	180	2.3	2005	280	2.3	2005	550	2.7
Tires III: super singles	N/A	N/A	N/A	N/A	N/A	N/A	2005	700	1.8
Tires IV: reduced rolling resistance from pneumatic blowing	N/A	N/A	N/A	N/A	N/A	N/A	2015	500	1.1
Transmission: lock-up, electronic controls, reduced friction	2005	750	1.8	2005	900	1.8	2005	1000	1.8
Diesel Engine I: turbocharged, direct injection with better thermal management	2003	700	4.5	2004	1000	7.2	N/A	N/A	N/A
Diesel Engine II: integrated starter/alternator with idle off and limited regenerative breaking	2005	1500	4.5	2005	1200	4.5	N/A	N/A	N/A
Diesel Engine III: improved engine with lower friction, better injectors, and efficient combustion	2012	2000	9.0	2008	2000	7.2	N/A	N/A	N/A
Diesel Engine IV: hybrid electric powertrain	2010	6000	36.0	2010	8000	36.0	N/A	N/A	N/A
Diesel Engine V: internal friction reduction - improved lubricants and and bearings	N/A	N/A	N/A	N/A	N/A	N/A	2005	500	1.8
Diesel Engine VI: inreased peak cylinder pressure	N/A	NA	N/A	N/A	N/A	N/A	2006	1000	3.6
Diesel Engine VII: improved injectors and more efficient combustion	N/A	N/A	N/A	N/A	N/A	N/A	2007	1500	5.4
Diesel Engine VIII: reduce waste heat improved thermal management	N/A	N/A	0.000	N/A	N/A	0.000	2010	2000	0.090
Gasoline Engine I: electronic fuel injection, DOHC, multiple values	2003	700	4.5	2003	1000	4.5	N/A	N/A	N/.A
Gasoline Engine II: Integrated starter/alternator with idle off and limited regenerative breaking	2005	1000	4.5	2005	1200	7.2	N/A	N/A	N/A

Table 7.7. Standard technology matrix for freight trucks (cont.)

	Medium Light Trucks			Medium Heavy Trucks			Heavy Trucks		
Technology Type	**Introd-uction Year**	**Capital Cost (2000$)**	**Incr. Fuel Econ. Improve-ment (%)**	**Introd-uction Year**	**Capital Cost (2000$)**	**Incr. Fuel Econ. Improve-ment (%)**	**Introd-uction Year**	**Capital Cost (2000$)**	**Incr, Fuel Econ. Improve-ment (%)**
Gasoline Engine III: direct injection (GDI)	2008	700	10.8	2008	1000	10.8	N/A	N/A	N/A
Gasoline Engine IV; hybrid electric powertrain	2010	6000	40.5	2010	8000	40.5	N/A	N/A	N/A
Weight Reduction I: high strength lightweight materials	2010	1300	4.5	2010	2000	4.5	2010	2000	9.000
Diesel Emission-Nox I: exhaust recirculation, timing retard, selective catalytic reduction	2002	250	-4.0	2003	400	-4.0	2003	500	-4.0
Diesel Emissions-NOx II: nitrogen enriched combustion air	2003	500	-0.5	2003	700	-0.5	2003	750	-0.5
Diesel Emissions-NOx III: non-thermal plasma catalyst	2007	1000	-1.5	2006	1200	-1.5	2007	1250	-1.5
Diesel Emissions-NOx IV: NOx absorber system	2007	1500	-3.0	2006	2000	-3.0	2007	2500	-3.0
Diesel Emission-PM I: oxidation catalyst	2002	150	-0.5	2002	200	-0.5	2002	250	-0.5
Diesel Emission-PM II: catalytic particulate filter	2006	1000	-1.5	2006	1250	-2.5	2006	1500	-1.5
Diesel Emission- HC/CO I: oxidation catalyst	2002	150	-0.5	2002	200	-0.5	2002	250	-0.5
Diesl Emission- HC/CO II: closed crankcase system	2005	50	0.0	2005	65	0.0	2005	75	0.0
Gasoline Emission- PM I: Improved oxidation catalyst	2005	250	-0.3	2005	350	-0.3	N/A	N/A	N/A
Gasoline Emission-Nox I: EGR/spark retard	2002	25	-0.015	2002	25	-0.015	N/A	N/A	0.000
Gasoline Emission-Nox II: oxygen sensors	2003	75	0.000	2003	75	0.000	N/A	N/A	0.000
Gasoline Emission-Nox III: secondary air/closed loop system	2008	50	0.000	2008	50	0.000	N/A	N/A	0.000
Gasoline Emission-HC/CO I: oxygen sensors	2003	75	0.000	2003	75	0.000	N/A	N/A	0.000
Gasoline Emission-HC/CO II: evap. canister w/improved vaccum, materials and connectors	2003	50	0.000	2003	50	0.000	N/A	N/A	0.000
Gasoline Emission-HC/CO III: oxidation catalyst	2005	250	-0.003	2005	350	0.000	N/A	N/A	0.000

The freight module uses projections of industrial output to estimate growth in freight truck travel. The industrial output is converted to an equivalent measure of volume output using freight adjustmentcoefficients [16],[17]. These freight adjustment coefficients vary by North American Industrial Classification System (NAICS) code with the deviation diminishing gradually over time toward parity. Freight truck load-factors (ton-miles per truck) by NAICS code are constants formulated from historical data [18].

Fuel economy of new freight trucks is dependent on the market penetration of various emission control technologies and advanced technology components [19]. For the advanced technology components, market penetration is determined as a function of technology type, cost effectiveness, and introduction year. Cost effectiveness is calculated as a function of fuel price, vehicle travel, fuel economy improvement, and incremental capital cost. Emissions control equipment is assumed to enter the market to meet regulated emission standards.

Heavy truck freight travel is estimated by class size and fuel type based on matching projected freight travel demand (measured by industrial output) to the travel supplied by the current fleet. Travel by vintage and size class is then adjusted so that total travel meets total demand.

Initial heavy vehicle travel, by vintage and size class, is derived using Vehicle Inventory and Use Survey (VIUS) data [20]. Initial freight truck stocks by vintage are obtained from R. L. Polk Co. and are distributed by fuel type using VIUS data [21]. Vehicle scrappage rates are also estimated using R. L. Polk Co. data [22].

Freight rail assumptions

The freight rail module uses the industrial output by NAICS code measured in real 1987 dollars and converts these dollars into an adjusted volume equivalent. Coal production from the NEMS Coal Market Module is used to adjust coal based rail travel. Freight rail adjustment coefficients (used to convert dollars to volume equivalents) are based on historical data and remain constant [23],[24]. Initial freight rail efficiencies are based on historic data taken from the Transportation Energy Databook [25]. The distribution of rail fuel consumption by fuel type is also based on historical data and remains constant over the projection [26]. Regional freight rail consumption estimates are distributed according to the State Energy Data Report [27].

Domestic and international shipping assumptions

Similar to the previous sub-module, the domestic freight shipping module uses the industrial output by NAICS code measured in real 1987 dollars and converts these dollars into an adjusted volume equivalent.

The freight adjustment coefficients (used to convert dollars to volume equivalents) are based on historical data. Domestic shipping efficiencies are based on the model developed by Argonne National Laboratory. The energy consumption in the international shipping module is a function of the total level of imports and exports. The distribution of domestic and international shipping fuel consumption by fuel type is based on historical data and remains constant throughout the forecast [28]. Regional domestic shipping consumption estimates are distributed according to the residual oil regional shares in the State Energy Data Report [29].

The air model

The air model is a thirteen region world demand and supply model (Table 7.8). For eac region, demand is computed for domestic travel (both takeoff and landing occur in the same region) and international travel (either takeoff or landing is in the region but not both). Once the demand for aircraft is determined, the stock efficiency module moves aircraft between regions to satisfy the demand.

Table 7.8. Thirteen regions for the world model

Region Number	Region	Major Countries in Region
1	United States	United States
2	Canada	Canada
3	Central America	Mexico
4	South America	Brazil
5	Europe	Western Europe
6	Africa	S. Africa
7	Mideast	Egypt
8	Russia	Russia
9	China	China
10	Northeast Asia	Japan, Korea
11	Southeast Asia	Vietnam
12	Southwest Asia	India
13	Oceania	Australia, New Zealand

Source: Jet Information Services, 2009 World Jet Inventory, data tables (2009)

Air travel demand assumptions

The air travel demand module calculates the domestic and international per-capita revenue passenger miles (RPM.P) for each region. Domestic and international revenue passenger miles are based on the historical data in Table 7.9, [30] per capita income for the U.S. per-capita GDP for the non-U.S. regions, and ticket prices. The revenue ton miles of air freight for the U.S. are based on merchandise exports, gross domestic product, and fuel cost. For the non U.S. regions, revenue ton miles are based on GDP growth in the region [31].

Airport capacity constraints based on the FAA's Airport Capacity Benchmark Report 2004 are incorporated into the air travel demand module using airport capacity measures. [32] Airport capacity is defined by the maximum number of flights per hour airports can routinely handle, the amount of time airports operate at optimal capacity, and passenger load factors. Capacity expansion is expected to be delayed due to the economic environment and fuel costs.

Aircraft stock/efficiency assumptions

The aircraft stock and efficiency module consists of a world regional stock model of wide body, narrow body, and regional jets by vintage. Total aircraft supply for a given year is based on the initial supply of aircraft for model year 2009, new passenger sales, and the survival rate by vintage (Table 7.10) [33]. New passenger sales are a function of revenue passenger miles and gross domestic product.

Wide and narrow body planes over 25 years of age are placed as cargo jets according to a cargo percentage varying from 50 percent of 25 year old planes to 100 percent of those aircraft 30 years and older. The available seat-miles per plane, which measure the carrying capacity of the airplanes by aircraft type increase gradually overtime. Domestic and international travel are combined into a single regional demand for seat-miles and passed to the Aircraft Fleet Efficiency Submodule, which adjusts the initial aircraft stocks to meet that demand. For each region, starting with the U.S., the initial stock is adjusted by moving aircraft between regions.

Technological availability, economic viability, and efficiency characteristics of new aircraft are assumed to grow at a fixed rate. Fuel efficiency of new aircraft acquisitions represents an improvement over the stock efficiency of surviving airplanes. A generic set of new technologies (Table 7.11) are introduced in different years and with a set of improved efficiencies over the base year (2007). Regional shares of all types of aircraft fuel use are assumed to be constant and are consistent with the State Energy Data Report estimate of regional jet fuel shares.

Legislation and regulations

Energy Independence and Security Act of 2007 (EISA2007)

The EISA2007 legislation requires the development of fuel economy standards for work trucks (8,500 lbs. to less than 10,000 lbs GVWR) and commercial medium- and heavy-duty on-highway vehicles (10,000 lbs or more GVWR). The new fuel economy standards require consideration of vehicle attributes and duty requirements and can prescribe standards for different classes of vehicles, such as buses used in urban operation or semi-trucks used primarily in highway operation. The Act provides a minimum of 4 full model years lead time before the new fuel economy standard is adopted and 3 full model years after the new fuel economy standard has been established before the fuel economy standards for work trucks can be modified. Because these fuel economy standards are pending and NEMS does not currently model fuel economy regulation for work trucks or commercial medium- and heavy- duty vehicles, this aspect of the Act is not included in *AEO2011*.

A fuel economy credit trading program is established based on EISA2007. Currently, CAFE credits earned by manufacturers can be banked for up to 3 years and can only be applied to the fleet (car or light truck) from which the credit was earned. Starting in model year 2011 the credit trading program will allow manufacturers whose automobiles exceed the minimum fuel economy standards to earn credits that can be sold to other manufacturers whose automobiles fail to achieve the prescribed standards. The credit trading program is designed to ensure that the total oil savings associated with manufacturers that exceed the prescribed standards are preserved when credits are sold to manufacturers that fail to achieve the prescribed standards. While the credit trading program begins in 2011, EISA2007 allows manufacturers to apply credits earned to any of the 3 model years prior to the model year the credits are earned, and to any of the 5 model years after the credits are earned. The transfer of credits within a manufacturer's fleet is limited to specific maximums. For model years 2011 through 2013, the maximum transfer is 1.0 mpg; for model years 2014 through 2017, the maximum transfer is 1.5 mpg; and for model years 2018 and later, the maximum credit transfer is 2.0 mpg. NEMS currently allows for sensitivity analysis of CAFE credit banking by manufacturer fleet, but does not model the trading of credits across manufacturers. The *AEO2011* does not consider trading of credits since this would require significant modifications to NEMS and detailed technology cost and efficiency data by manufacturer, which is not readily available.

Table 7.9. 2009 Regional population, gdp, per capita gdp domestic and international rpm and per-capita rpm

Region	Population (million)	GDP (2006$)	GDP_PC
United States	308.2	12,987	42,140.8
Canada	33.5	1,240	37,063.8
Central	209.4	1,793	8,563.6
Central Amercia	377.2	3,773	10,001.5
Europe	545	15,150	27,817.6
Africa	1,010.0	2,432	2,408.0
Middle East	208.7	2,797	13,401.7
Russia	340.1	2,704	7,952.7
China	1,343.8	8,431	6,274.1
Northeast Asia	176.3	5,047	28,627.6
Southeast Asia	1,044.4	3,423	3,277.7
Southwest Asia	1,203.0	4,122	3,426.4
Oceania	25.4	896	35,277.1

Region	RPM (billion)	RPM_PC (thousand)
Domestic		
United States	551.8	1,790.4
Canada	26.5	792.7
Central America	16.1	77.0
South America	56.9	150.7
Europe	387.4	711.4
Africa	22.4	22.2
Middle East	30.3	145.2
Russia	30.4	89.3
China	168.9	125.7
Northeast Asia	54.7	310.5
Southeast Asia	58.7	56.2
Southwest Asia	26.9	22.4
Oceania	46.4	1,825.9
International		
United States	228.0	739.7
Canada	50.5	1,508.5
Central America	63.5	303.1
South America	52.0	137.7
Europe	351.0	644.5
Africa	56.3	55.7
Middle East	98.4	471.2
Russia	25.5	74.8
China	68.6	51.1
Northeast Asia	88.0	499.2
Southeast Asia	124.1	118.8
Southwest Asia	41.0	34.1
Oceania	40.5	1,596.4

Source: Global Insight 2006 chained weighted dollars, Boeing Current Market Outlook 2009

Table 7.10. 2009 Regional passenger and cargo aircraft supply

		Age of Aircraft (years)				
Aircraft Type	**New**	**1-10**	**11-20**	**21-30**	**>30**	**Total**
Passenger						
Narrow Body						
United States	102	1584	1276	589	187	3738
Canada	11	132	81	22	7	253
Central	6	203	41	80	51	381
Central Amercia	35	253	126	149	104	667
Europe	230	1629	919	165	21	2964
Africa	10	157	133	163	100	563
Middle East	66	201	127	60	32	486
Russia	30	176	368	308	234	1116
China	157	745	258	12	0	1172
Northeast Asia	25	127	109	12	3	276
Southeast Asia	40	212	206	119	25	602
Southwest Asia	39	188	58	34	6	325
Oceania	14	161	34	2	1	212
Wide Body						
United States	11	251	251	122	19	654
Canada	2	31	32	24	0	89
Central America	1	11	9	5	0	26
South America	5	39	40	7	2	93
Europe	34	377	338	39	5	793
Africa	7	55	46	30	14	152
Middle East	39	214	114	73	9	449
Russia	7	21	70	58	0	156
China	6	135	114	1	0	256
Northeast Asia	14	153	179	18	0	364
Southeast Asia	31	192	155	24	8	410
Southwest Asia	8	50	35	24	1	118
Oceania	7	52	60	4	0	123
Regional Jets						
United States	48	1809	197	6	9	2069
Canada	4	120	40	0	25	189
Central America	1	74	32	3	0	110
South America	21	45	38	8	3	117
Europe	83	465	338	39	1	926
Africa	5	38	36	34	15	128
Middle East	12	59	47	4	4	126
Russia	3	52	36	65	30	186
China	20	92	8	2	0	122
Northeast Asia	8	12	2	0	0	22
Southeast Asia	2	12	21	26	7	68
Southwest Asia	1	9	7	4	3	24
Oceania	5	20	33	5	0	63
Cargo						
Narrow Body						
United States	0	3	72	122	224	421
Canada	0	0	1	15	19	35
Central	0	1	2	4	9	16
Central America	0	0	0	14	43	57
Europe	0	1	28	57	10	96
Africa	0	0	4	15	58	77
Middle East	0	0	2	5	8	15
Russia	1	4	3	2	5	15

Table 7.10. 2009 Regional passenger and cargo aircraft supply (cont)

		Age of Aircraft (years)				
Aircraft Type	**New**	**1-10**	**11-20**	**21-30**	**>30**	**Total**
China	0	2	20	10	0	32
Northeast Asia	0	0	0	0	0	0
Southeast Asia	0	0	0	12	10	22
Southwest Asia	0	0	3	9	4	16
Oceania	0	0	0	9	3	12
Wide Body						
United States	7	93	215	214	103	632
Canada	0	0	0	3	2	5
Central America	0	3	0	3	1	7
South America	2	5	1	6	5	19
Europe	7	36	39	63	7	152
Africa	0	0	1	2	1	4
Middle East	7	5	15	18	5	50
Russia	0	1	8	3	0	12
China	6	28	43	6	0	83
Northeast Asia	0	35	23	0	0	58
Southeast Asia	0	35	18	5	0	58
Southwest Asia	0	0	5	3	1	9
Oceania	0	0	0	0	0	0
Regional Jets						
United States	0	0	1	0	0	1
Canada	0	0	0	0	0	0
Central America	0	0	2	0	0	2
South America	0	0	0	0	0	0
Europe	0	0	15	11	0	26
Africa	0	0	0	0	1	1
Middle East	0	0	0	0	0	0
Russia	0	0	0	0	0	0
China	0	0	0	0	0	0
Northeast Asia	0	0	0	0	0	0
Southeast Asia	0	0	1	0	0	1
Southwest Asia	0	0	0	0	0	0
Oceania	0	0	1	1	0	2
Survival Curve (fraction)	**New**	**5**	**10**	**20**	**35**	
Narrow Body	1.000	0.9998	0.9992	0.9960	0.9200	
Wide Body	1.000	0.9980	0.9954	0.9860	0.8500	
Regional Jets	1.000	0.9967	0.9900	0.9400	0.8350	

Source: Jet Information Services, 2009 World Jet Inventory (2009)

Table 7.11. Standard technology matrix for air travel

Technology	Introduction Year	Fractional Efficiency Improvement	Jet Fuel Trigger Price (87$/gal)
Technology #1	2008	0.03	1.34
Technology #2	2014	0.07	1.34
Technology #3	2020	0.11	1.34
Technology #4	2025	0.15	1.34
Technology #5	2030	0.20	1.34
Technology #6	2018	0.00	1.34

Source: Jet Information Services, 2009 World Jet Inventory, data tables (2009)

The CAFE credits specified under the Alternative Motor Fuels Act (AMFA) through 2019 are extended. Prior to passage of this Act, the CAFE credits under AMFA were scheduled to expire after model year 2010. Currently, 1.2 mpg is the maximum CAFE credit that can be earned from selling alternative fueled vehicles. EISA2007 extends the 1.2 mpg credit maximum through 2014 and reduces the maximum by 0.2 mpg for each following year until it is phased out by model year 2020. NEMS does model CAFE credits earned from alternative fuel vehicles sales.

American Recovery and Reinvestment Act of 2009 and Energy Improvement and Extension Act of 2008

ARRA Title I, Section 1141, modified the EIEA2008 Title II, Section 205, tax credit for the purchase of new, qualified plug-in electric drive motor vehicles. According to the legislation, a qualified plug-in electric drive motor vehicle must draw propulsion from a traction battery with at least 4 kilowatthours of capacity and be propelled to a significant extent by an electric motor which draws electricity from a battery that is capable of being recharged from an external source of electricity.

The tax credit for the purchase of a plug-in electric vehicle is $2,500, plus, starting at a battery capacity of 5 kilowatthours, an additional $417 per kilowatthour battery credit up to a maximum of $7,500 per vehicle. The tax credit eligibility and phase-out are specific to an individual vehicle manufacturer. The credits are phased out once a manufacturer's cumulative sales of qualified vehicles reach 200,000. The phaseout period begins two calendar quarters after the first date in which a manufacturer's sales reach the cumulative sales maximum after December 31, 2009. The credit is reduced to 50 percent of the total value for the first two calendar quarters of the phase-out period and then to 25 percent for the third and fourth calendar quarters before being phase out entirely thereafter. The credit applies to vehicles with a gross vehicle weight rating of less than 14,000 pounds.

ARRA also allows a tax credit of 10 percent against the cost of a qualified electric vehicle with a battery capacity of at least 4 kilowatthours subject to the same phase out rules as above. The tax credits for qualified plug-in electric drive motor vehicles and electric vehicles are included in *AEO2011*.

Energy Policy Act of 1992 (EPACT)

Fleet alternative-fuel vehicle sales necessary to meet the EPACT regulations are derived based on the mandates as they currently stand and the Commercial Fleet Vehicle Module calculations. Total projected AFV sales are divided into fleets by government, business, and fuel providers (Table 7.12).

Because the commercial fleet model operates on three fleet type representations (business, government, and utility), the federal and state mandates are weighted by fleet vehicle stocks to create a composite mandate for both. The same combining methodology is used to create a composite mandate for electric utilities and fuel providers based on fleet vehicle stocks [34].

Low Emission Vehicle Program (LEVP)

The LEVP was originally passed into legislation in 1990 in the State of California. It began as the implementation of a voluntary opt-in pilot program under the purview of Clean Air Act Amendments of 1990 (CAAA90), which included a provision that other States could opt in to the California program to achieve lower emissions levels than would otherwise be achieved through CAAA90. 14 states have elected to adopt the California LEVP.

The LEVP is an emissions-based policy, setting sales mandates for 6 categories of low-emission vehicles: low-emission vehicles (LEVs), ultra-low-emission vehicles (ULEVs), super-ultra low emission vehicles (SULEVs), partial zero-emission vehicles (PZEVs), advanced technology partial zero emission vehicles (AT-PZEVs), and zero-emission vehicles (ZEVs). The LEVP requires that in 2005 10 percent of a manufacturer's sales are ZEVs or equivalent ZEV earned credits, increasing to 11 percent in 2009, 12 percent in 2012, 14 percent in 2015, and 16 percent in 2018 where it remains constant thereafter. In August 2004, CARB enacted further amendments to the LEVP that place a greater emphasis on emissions reductions from PZEVs and AT-PZEVs and

Table 7.12. EPACT legislative mandates for AFV purchases by fleet type and year
percent

Year	Federal	State	Fuel Providers	Electric Utilities
2005	75	75	70	90

Source: EIA, Energy Efficiency and Renewable Energy (Washington, DC, 2005) http://www1.eere.energy.gov/femp/about/fleet-requirements.html, http://www1.eere.energy.gov/vehicles and fuels/epact/state/state-gov.html.

requires that manufacturers produce a minimum number of fuel cell and electric vehicles. In addition, manufacturers are allowed to adopt alternative compliance requirements for ZEV sales that are based on cumulative fuel cell vehicle sales targets for vehicles sold in all States participating in California's LEVP. Under the alternative compliance requirements, ZEV credits can also be earned by selling battery electric vehicles. Currently, all manufacturers have opted to adhere to the alternative compliance requirements. The mandate still includes phase-in multipliers for pure ZEVs and allows 20 percent of the sales requirement to be met with AT-PZEVs and 60 percent of the requirement to be met with PZEVs. AT-PZEVs and PZEVs are allowed 0.2 credits per vehicle. EIA assumes that credit allowances for PZEVs will be met with conventional vehicle technology, hybrid vehicles will be sold to meet the AT-PZEV allowances, and that hydrogen fuel cell vehicles will be sold to meet the pure ZEV requirements under the alternative compliance path.

Transportation alternative cases

High and Low Technology cases

In the high technology and low technology cases for cars and light trucks, the conventional fuel saving technology characteristics are based on NHTSA and EPA values [35]. Tables 7.13 7.14, 7.15, 7.16 summarize the High and Low Technology matrices for cars and light trucks. Tables 7.17 and 7.18 reflect the high and low technology case assumptions for freight trucks. These reflect optimistic and pessimistic values, with respect to efficiency improvement and capital cost, for advanced engine and emission control technologies as reported by ANL [36]. For the Air Module, the high technology case reflects earlier introduction years for the new aircraft technologies and a greater penetration share. The low technology case simulates a delay in the introduction of new aircraft technologies. Tables 7.19 and 7.20 reflect these cases.

Table 7.13. High technology matrix for cars

	Incremental Fuel Efficiency Change (%)	Incremental Cost (1990$)	Incremental Cost ($/Unit Wt.)	Absolute Incremental Weight (Lbs.)	Per Unit Incremental Weight (Lbs./Unit Wt.)	Introduc-tion Year	Horse-power Change (%)
Unit Body Construction	4	100	0	0	-6	1980	0
Material Substitution II	3.3	0	0.4	0	-5	1990	0
Material Substitution III	6.6	0	0.6	0	-10	1998	0
Material Substitution IV	9.9	0	0.9	0	-15	2006	0
Material Substitution V	13.2	0	1.2	0	-20	2014	0
Drag Reduction II	1.6	16	0	0	0	1988	0
Drag Reduction III	3.2	32	0	0	0.2	1992	0
Drag Reduction IV	6.3	45	0	0	0.5	2000	0
Drag Reduction V	8	53.5	0	0	1	2010	0
Roll-Over Technology	-1.5	100	0	0	2.2	2004	0
Side Impact Technology	-1.5	100	0	0	2.2	2004	0
Adv Low Loss Torque Converter	2	25	0	0	0	1999	0
Early Torque Converter Lockup	1	25.6	0	0	0	2002	0
Aggressive Shift Logic	2	30.5	0	0	0	1999	0
4-Speed Automatic	4.5	285	0	10	0	1980	0
5-Speed Automatic	8	106.5	0	20	0	1995	0
6-Speed Automatic	3.4	259	0	30	0	2003	0
6-Speed Manual	2	91.4	0	20	0	1995	0
CVT	8	240.5	0	-25	0	1998	0
Automated Manual Trans	12	120.4	0	0	0	2004	0
Roller Cam	2	16	0	0	0	1980	0
OHC/AdvOHV-4 Cylinder	3	93.1	0	0	0	1980	2.5
OHC/AdvOHV-6 Cylinder	3	108.9	0	0	0	1987	2.5
OHC/AdvOHV-8 Cylinder	3	124.7	0	0	0	1986	2.5
4-Valve/4-Cylinder	8.8	205	0	10	0	1988	4.25
4-Valve/6-Cylinder	8.8	280	0	15	0	1992	4.25
4 Valve/8-Cylinder	8.8	320	0	20	0	1994	4.25
5 Valve/6-Cylinder	9	300	0	18	0	1998	5
VVT-4 Cylinder	3	35	0	10	0	1994	1.25
VVT-6 Cylinder	3	87.5	0	20	0	1993	1.25
VVT-8 Cylinder	3	90	0	20	0	1993	1.25
VVL-4 Cylinder	3	144.3	0	25	0	1997	2.5
VVL-6 Cylinder	3	220.0	0	40	0	2000	2.5
VVL-8 Cylinder	3	285.0	0	50	0	2000	2.5
Camless Valve Actuation-4cyl	15.1	363.8	0	35	0	2020	3.25
Camless Valve Actuation-6cyl	15.1	513.0	0	55	0	2020	3.25
Camless Valve Actuation-8cyl	15.1	675.5	0	75	0	2020	3.25
Cylinder Deactivation	7.5	60.1	0	10	0	2004	0
Turbocharging/ Supercharging	7.5	324.7	0	-100	0	1980	3.75
Engine Friction Reduction I	2.3	54	0	0	0	1992	0.75
Engine Friction Reduction II	3.5	60.9	0	0	0	2000	1.75
Engine Friction Reduction III	5	52.1	0	0	0	2008	1.75
Engine Friction Reduction IV	6.5	177	0	0	0	2016	2.25
Stoichiometric GDI/4-Cylinder	2.9	234.9	0	20	0	2006	2.5
Stoichiometric GDI/6-Cylinder	2.9	307.9	0	30	0	2006	2.5
Lean Burn GDI	10	640.5	0	20	0	2020	0
5W-30 Engine Oil	1	3	0	0	0	1998	0
5W-20 Engine Oil	2	16.7	0	0	0	2003	0
OW-20 Engine Oil	3.1	150	0	0	0	2030	0
Electric Power Steering	2	84.2	0	0	0	2004	0
Improved Alternator	0.3	15	0	0	0	2005	0
Improved Oil/Water Pump	0.5	10	0	0	0	2000	0
Electric Oil/Water Pump	1	93.4	0	0	0	2007	0
Tires II	2	6.1	0	-8	0	1995	0
Tires III	3.5	12.3	0	-12	0	2005	0
Tires IV	5	16.9	0	-16	0	2015	0
Front Wheel Drive	6	250	0	0	-6	1980	0
Four Wheel Drive Improvements	2	93.8	0	0	-1	2000	0
42V-Launch Assist and Regen	7.5	280	0	80	0	2005	-2.5
42V-Engine Off at Idle	7.5	496.6	0	45	0	2005	0
Tier 2 Emissions Technology	-1	120	0	20	0	2006	0
Increased Size/Weight	-1.7	0	0	0	2.55	2003	0
Variable Compression Ratio	4	350	0	25	0	2015	0

Source: Energy and Environmental Analysis, Documentation of Technology included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks (September, 2002). National Research Council, Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards (Copyright 2002). National Highway Traffic Safety Administration, Corporate Average Fuel Economy for MY 2011-2015 Passenger Cars and Light Trucks (April 2008). U.S. Environmental Protection Agency, Interim Report: New Powertrain Technologies and Their Projected Costs (October 2005)

Table 7.14. High technology matrix for light trucks

	Fuel Efficiency Change (%)	Incremental Cost (2000$)	Incremental Cost ($/Unit Wt.)	Absolute Incremenal Weight (Lbs.)	Per Unit Incremental Weight (Lbs./Unit Wt.)	Introduc-tion Year	Horse-power Change (%)
Unit Body Construction	4	100	0	0	-6	1980	0
Material Substitution II	3.3	0	0.4	0	-5	1994	0
Material Substitution III	6.6	0	0.6	0	-10	2002	0
Material Substitution IV	9.9	0	0.9	0	-15	2010	0
Material Substitution V	13.2	0	1.2	0	-20	2018	0
Drag Reduction II	2.3	32	0	0	0	1992	0
Drag Reduction III	4.1	57	0	0	0.2	1998	0
Drag Reduction IV	6.4	89	0	0	0.5	2006	0
Drag Reduction V	7.8	109	0	0	1	2014	0
Roll-Over Technology	-1.5	100	0	0	2.2	2006	0
Side Impact Technology	-1.5	100	0	0	2.2	2006	0
Adv Low Loss Torque Converter	2	25	0	0	0	2005	0
Early Torque Converter Lockup	0.5	25.6	0	0	0	2003	0
Aggressive Shift Logic	2.0	35	0	0	0	1999	0
4-Speed Automatic	4.5	285	0	10	0	1980	0
5-Speed Automatic	8	106.5	0	20	0	1995	0
6-Speed Automatic	3.4	259	0	30	0	2003	0
6-Speed Manual	2	91.4	0	20	0	1995	0
CVT	8	130.0	0	-25	0	1998	0
Automated Manual Trans	3.4	120.4	0	0	0	2004	0
Roller Cam	2	16	0	0	0	1985	0
OHC/AdvOHV-4 Cylinder	3.5	93.1	0	0	0	1980	2.5
OHC/AdvOHV-6 Cylinder	3.5	108.9	0	0	0	1990	2.5
OHC/AdvOHV-8 Cylinder	3.5	124.7	0	0	0	1990	2.5
4-Valve/4-Cylinder	7.0	205	0	10	0	1998	4.25
4-Valve/6-Cylinder	7.0	280	0	15	0	2000	4.25
4 Valve/8-Cylinder	7.0	320	0	20	0	2000	4.25
5 Valve/6-Cylinder	7.0	300	0	18	0	2010	5
VVT-4 Cylinder	3	48.9	0	10	0	1998	1.25
VVT-6 Cylinder	3	97.8	0	20	0	1997	1.25
VVT-8 Cylinder	3	97.8	0	20	0	1997	1.25
VVL-4 Cylinder	3	144.3	0	25	0	2002	2.5
VVL-6 Cylinder	3	220	0	40	0	2001	2.5
VVL-8 Cylinder	3	285	0	50	0	2006	2.5
Camless Valve Actuation-4cyl	15.1	363.8	0	35	0	2020	3.25
Camless Valve Actuation-6cyl	15.1	513	0	55	0	2020	3.25
Camless Valve Actuation-8cyll	15.1	657.5	0	75	0	2020	3.25
Cylinder Deactivation	7.5	60.1	0	10	0	2004	0
Turbocharging/Supercharging	7.5	339	0	-100	0	1987	3.75
Engine Friction Reduction I	2.5	25	0	0	0	1992	0.75
Engine Friction Reduction II	3.5	31.2	0	0	0	2000	1.25
Engine Friction Reduction III	5	62.5	0	0	0	2010	1.75
Engine Friction Reduction IV	6.5	67.5	0	0	0	2016	2.75
Stoichiometric GDI/4-Cylinder	2.9	234.9	0	20	0	2008	2.5
Stoichiometric GDI/6-Cylinder	2.9	307.9	0	30	0	2010	2.5
Lean Burn GDI	11.5	640.5	0	20	0	2010	0
5W-30 Engine Oil	0.8	4	0	0	0	1998	0
5W-20 Engine Oil	2	16.7	0	0	0	2003	0
OW-20 Engine Oil	3.1	150	0	0	0	2030	0
Electric Power Steering	2	84.2	0	0	0	2005	0
Improved Alternator	0.3	15	0	0	0	2005	0
Improved Oil/Water Pump	0.5	10	0	0	0	2000	0
Electric Oil/Water Pump	1	93.4	0	0	0	2008	0
Tires II	0.0	30	0	-8	0	1995	0
Tires III	1.5	5.6	0	-12	0	2005	0
Tires IV	3.5	11.8	0	-16	0	2015	0
Front Wheel Drive	2	250	0	0	-3	1984	0
Four Wheel Drive Improvements	1.5	93.8	0	0	-1	2000	0
42V-Launch Assist and Regen	7.5	280	0	80	0	2005	-2.5
42V-Engine Off at Idle	7.5	434.9	0	45	0	2005	0
Tier 2 EmissionsTechnology	-1	160	0	20	0	2006	0
Increased Size/Weight	-2.5	0	0	0	3.75	2006	0
Variable Compression Ratio	4	350	0	25	0	2015	0

Source: Energy and Enviromental Analysis, Documentation of Technology included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks (September, 2002). National Research Council, Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards (Copyright 2002). National Highway Traffic Safety Administration, Corporate Average Fuel Economy for MY 2011-2015 Passenger Cars and Light Trucks (April 2008). U.S. Environmental Protection Agency, Interim Report: New Powertrain Technologies and Their Projected Costs (October 2005)

Table 7.15. Low technology matrix for cars[1]

	Fuel Efficiency Change (%)	Incremental Cost (2000$)	Incremental Cost ($/Unit Wt.)	Absolute Incremental Weight (Lbs.)	Per Unit Incremental Weight (Lbs./Unit Wt.)	Introduction Year	Fractional Horse-power Change (%)
Unit Body Construction	4	100	0	0	-6	1980	0
Material Substitution II	3.3	0	0.4	0	-5	1990	0
Material Substitution III	6.6	0	0.6	0	-10	1998	0
Material Substitution IV	9.9	0	0.9	0	-15	2006	0
Material Substitution V	13.2	0	1.2	0	-20	2014	0
Drag Reduction II	1.5	16.0	0	0	0	1988	0
Drag Reduction III	3.0	32.0	0	0	0.2	1992	0
Drag Reduction IV	4.2	45.0	0	0	0.5	2000	0
Drag Reduction V	5.0	53.5	0	0	1	2010	0
Roll-Over Technology	-1.5	100	0	0	2.2	2004	0
Side Impact Technology	-1.5	100	0	0	2.2	2004	0
Adv Low Loss Torque Converter	2	25	0	0	0	1999	0
Early Torque Converter Lockup	0.5	25.6	0	0	0	2002	0
Aggressive Shift Logic	1.0	30.5	0	0	0	1999	0
4-Speed Automatic	4.5	285	0	10	0	1980	0
5-Speed Automatic	2.5	106.5	0	20	0	1995	0
6-Speed Automatic	2	259	0	30	0	2003	0
6-Speed Manual	0.5	91.4	0	20	0	1995	0
CVT	2	240.5	0	-25	0	1998	0
Automated Manual Trans	4.0	175.0	0	0	0	2004	0
Roller Cam	2	16	0	0	0	1980	0
OHC/AdvOHV-4 Cylinder	3.5	105.0	0	0	0	1980	2.5
OHC/AdvOHV-6 Cylinder	1.5	122.5	0	0	0	1987	2.5
OHC/AdvOHV-8 Cylinder	1.5	140.0	0	0	0	1986	2.5
4-Valve/4-Cylinder	8	205	0	10	0	1988	4.25
4-Valve/6-Cylinder	8	280	0	15	0	1992	4.25
4 Valve/8-Cylinder	8	320	0	20	0	1994	4.25
5 Valve/6-Cylinder	8	300	0	18	0	1998	5
VVT-4 Cylinder	1.0	50.4	0	10	0	1994	1.25
VVT-6 Cylinder	1.0	114.4	0	20	0	1993	1.25
VVT-8 Cylinder	1.0	178.5	0	20	0	1993	1.25
VVL-4 Cylinder	2.0	178	0	25	0	1997	2.5
VVL-6 Cylinder	2.0	270	0	40	0	2000	2.5
VVL-8 Cylinder	2.0	349	0	50	0	2000	2.5
Camless Valve Actuation-4cyl	12.1	433	0	35	0	2020	3.25
Camless Valve Actuation-6cyl	12.1	609.4	0	55	0	2020	3.25
Camless Valve Actuation-8cyl	12.1	785.8	0	75	0	2020	3.25
Cylinder Deactivation	4.0	245	0	10	0	2004	0
Turbocharging/Supercharging	5.0	324.7	0	-100	0	1980	3.75
Engine Friction Reduction I	2.3	54	0	0	0	1992	0.75
Engine Friction Reduction II	2.0	60.9	0	0	0	2000	1.25
Engine Friction Reduction III	3.0	196.4	0	0	0	2008	1.75
Engine Friction Reduction IV	6.5	177	0	0	0	2016	2.25
Stoichiometric GDI/4-Cylinder	1.9	352	0	20	0	2006	2.5
Stoichiometric GDI/6-Cylinder	1.9	447.0	0	30	0	2006	2.5
Lean Burn GDI	10.0	640.5	0	20	0	2020	0
5W-30 Engine Oil	0.5	6.0	0	0	0	1998	0
5W-20 Engine Oil	2	16.7	0	0	0	2003	0
OW-20 Engine Oil	3.1	150	0	0	0	2030	0
Electric Power Steering	1.0	96.2	0	0	0	2004	0
Improved Alternator	0.3	15	0	0	0	2005	0
Improved Oil/Water Pump	0.5	10	0	0	0	2000	0
Electric Oil/Water Pump	1	93.4	0	0	0	2007	0
Tires II	1.5	35	0	-8	0	1995	0
Tires III	1.5	35	0	-12	0	2005	0
Tires IV	1.5	35	0	-16	0	2015	0
Front Wheel Drive	6	250	0	0	-6	1980	0
Four Wheel Drive Improvements	1.3	93.8	0	0	-1	2000	0
42V-Launch Assist and Regen	7.5	280	0	80	0	2005	-2.5
42V-Engine Off at Idle	5.5	496.6	0	45	0	2005	0
Tier 2 Emissions Technology	-1	120	0	20	0	2006	0
Increased Size/Weight	-1.7	0	0	0	2.55	2006	0
Variable Compression Ratio	4	350	0	25	0	2015	0

[1]Fractional changes refer to the percentage change from the 1990 values.

Sources: Energy and Environment Analysis, Documentation of Technology included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks (September, 2002). National Research Council, Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards (Copyright 2002). National Highway Traffic Safety Administration, Corporate Average Fuel Economy for MY 2011-2015 Passenger Cars and Light Trucks (April 2008). U.S. Environmental Protection Agency, Interim Report: New Powertrain Technologies and Their Projected Costs (October 2005)

Table 7.16. Low technology matrix for light trucks[1]

	Fractional Fuel Efficiency Change (%)	Incremental Cost (2000$)	Incremental Cost ($/UnitWt.)	Absolute Incremental Weight (Lbs.)	Per Unit Incremental Weight (Lbs./UnitWt.)	Introduction Year	Fractional Horsepower Change (%)
Unit Body Construction	4	100	0	0	-6	1980	0
Material Substitution II	3.3	0	0.4	0	-5	1994	0
Material Substitution III	6.6	0	0.6	0	-10	2002	0
Material Substitution IV	9.9	0	0.9	0	-15	2010	0
Material Substitution V	13.2	0	1.2	0	-20	2018	0
Drag Reduction II	1.5	32	0	0	0	1992	0
Drag Reduction III	4.1	57	0	0	0.2	1998	0
Drag Reduction IV	6.4	89	0	0	0.5	2006	0
Drag Reduction V	7.8	109	0	0	1	2014	0
Roll-Over Technology	-1.5	100	0	0	2.2	2006	0
Side Impact Technology	-1.5	100	0	0	2.2	2006	0
Adv Low Loss Torque Converter	2	25	0	0	0	2005	0
Early Torque Converter Lockup	0.5	25.6	0	0	0	2003	0
Aggressive Shift Logic	1.5	30.5	0	0	0	1999	0
4-Speed Automatic	4.5	285	0	10	0	1980	0
5-Speed Automatic	2.5	112	0	20	0	1995	0
6-Speed Automatic	2.0	259.0	0	30	0	2003	0
6-Speed Manual	0.5	91.4	0	20	0	1995	0
CVT	3.0	200	0	-25	0	1998	0
Automated Manual Trans	3.4	157.5	0	0	0	2004	0
Roller Cam	2	16	0	0	0	1985	0
OHC/AdvOHV-4 Cylinder	1.8	105	0	0	0	1980	2.5
OHC/AdvOHV-6 Cylinder	1.8	122.5	0	0	0	1990	2.5
OHC/AdvOHV-8 Cylinder	1.8	140	0	0	0	1990	2.5
4-Valve/4-Cylinder	7	205	0	10	0	1998	4.25
4-Valve/6-Cylinder	7	280	0	15	0	2000	4.25
4 Valve/8-Cylinder	7	320	0	20	0	2000	4.25
5 Valve/6-Cylinder	7	300	0	18	0	2010	5
VVT-4 Cylinder	1.0	48.9	0	10	0	1998	1.25
VVT-6 Cylinder	1.0	97.8	0	20	0	1997	1.25
VVT-8 Cylinder	1.0	97.8	0	20	0	1997	1.25
VVL-4 Cylinder	2.0	178	0	25	0	2002	2.5
VVL-6 Cylinder	2.0	270	0	40	0	2001	2.5
VVL-8 Cylinder	2.0	349	0	50	0	2006	2.5
Camless Valve Actuation-4cyl	12.1	433	0	35	0	2020	3.25
Camless Valve Actuation-6cyl	12.1	609.4	0	55	0	2020	3.25
Camless Valve Actuation-8cyl	12.1	785.8	0	75	0	2020	3.25
Cylinder Deactivation	4.0	190.4	0	10	0	2004	0
Turbocharging/Supercharging	5.0	650	0	-100	0	1987	3.75
Engine Friction Reduction I	2.0	36	0	0	0	1992	0.75
Engine Friction Reduction II	1.5	63	0	0	0	2000	1.25
Engine Friction Reduction III	1.5	235.7	0	0	0	2010	1.75
Engine Friction Reduction IV	1.5	177	0	0	0	2016	2.25
Stoichiometric GDI/4-Cylinder	1.9	352.8	0	20	0	2008	2.5
Stoichiometric GDI/6-Cylinder	1.9	447.4	0	30	0	2010	2.5
Lean Burn GDI	10.0	640.5	0	20	0	2010	0
5W-30 Engine Oil	0.5	6.0	0	0	0	1998	0
5W-20 Engine Oil	1.0	37.5	0	0	0	2003	0
OW-20 Engine Oil	3.1	150	0	0	0	2030	0
Electric Power Steering	1.0	96.2	0	0	0	2005	0
Improved Alternator	0.3	15	0	0	0	2005	0
Improved Oil/Water Pump	0.5	10	0	0	0	2000	0
Electric Oil/Water Pump	1	93.4	0	0	0	2008	0
Tires II	0.0	30	0	-8	0	1995	0
Tires III	1.0	35	0	-12	0	2005	0
Tires IV	1.0	35	0	-16	0	2015	0
Front Wheel Drive	2	250	0	0	-3	1984	0
Four Wheel Drive Improvements	1.0	93.8	0	0	-1	2000	0
42V-Launch Assist and Regen	7.5	280	0	80	0	2005	-2.5
42V-Engine Off at Idle	5.5	434.9	0	45	0	2005	0
Tier 2 Emissions Technology	-1	160	0	20	0	2006	0
Increased Size/Weight	-2.5	0	0	0	3.75	2006	0
Variable Compression Ratio	4	350	0	25	0	2015	0

[1]Fractional changes refer to the percentage change from the 1990 values.

Sources: Energy and Environment Analysis, Documentation of Technology included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks (September, 2002). National Research Council, Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards (Copyright 2002). National Highway Traffic Safety Administration, Corporate Average Fuel Economy for MY 2011-2015 Passenger Cars and Light Trucks (April 2008). U.S. Environmental Protection Agency, Interim Report: New Powertrain Technologies and Their Projected Costs (October 2005)

Table 7.17. High technology matrix for freight trucks

	Medium Light Trucks			Medium Heavy Trucks			Heavy Trucks		
Technology Type	Introduction Year	Capital Cost (2000$)	Incr. Fuel Econ. Improvement (%)	Introduction Year	Capital Cost (2000$)	Incr. Fuel Econ. Improvement (%)	Introduction Cost	Capital Cost (2000$)	Incr. Fuel Econ. Improvement (%)
Areo dynamic I: Cab top deflector, sloping hood and cab side flares	N/A	N/A	N/A	1995	750	2.8	1995	750	2.3
Closing/covering of gap between trackor and trailer aero dynamic bumper, underside air baffles, wheel well covers	N/A	N/A	N/A	2004	800	4.1	2008	1800	2.3
Trailer leading and trailing edge curvatures	NA	N/A	N/A	2005	400	1.3	2005	500	1.6
Aero Dynamics IV: pneumatic blowing	N/A	N/A	N/A	N/A	N/A	N/A	2010	2500	6.0
Tires I: radials	1995	40	2.8	1995	180	2.8	1995	300	2.4
Tires II: low rolling resistance	2004	180	3.3	2005	280	3.3	2005	550	3.7
Tires III: super singles	N/A	N/A	N/A	N/A	N/A	N/A	2005	700	2.8
Tires IV: reduced rolling resistance from pneumatic blowing	N/A	N/A	N/A	N/A	N/A	N/A	2015	500	1.1
Transmission: lock-up, electronic controls, reduced friction	2005	750	2.3	2005	900	2.3	2005	1000	2.3
Diesel Engine I:turbo-charged, direct injection with better thermal management	2003	600	4.5	2004	900	7.2	N/A	N/A	N/A
Diesel Engine II:integrated starter/alternator with idle off and limited regenerative breaking	2005	1500	4.5	2005	1200.	4.5	N/A	N/A	N/A
Diesel Engine III: improved engine with lower friction, better injectors, and efficient combustion	2012	2000	8.0	2008	2000	8.2	N/A	N/A	N/A
Diesel Engine IV: hybrid electric powertrain	2010	6000	36.0	2010	7000	36.0	N/A	N/A	N/A
Diesel Engine V: internal friction reduction - improved lubricants and bearings	N/A	N/A	N/A	N/A	N/A	N/A	2005	500	1.8
Diesel Engine VI: increased peak cylinder pressure	N/A	N/A	N/A	N/A	N/A	N/A	2006	1000	3.6
Diesel Engine VII: improved injectors and more efficient ore efficient combustion	N/A	N/A	N/A	N/A	N/A	N/A	2007	1500	5.4
Diesel Engine VIII: reduce waste heat improved thermal waste heat improved thermal magement	N/A	N/A	N/A	N/A	N/A	N/A	2010	2000	9.0
Gasoline Engine I: electronid fuel injection, DOHC, multiple values	2003	700	4.5	2003	1000	4.5	N/A	N/A	N/A
Gasoline Engine II: integrated starter/alternator with idle off and limited reogenerative breaking	2005	1000	4.5	2005	1200	7.2	N/A	N/A	N/A
Gasoline Engine III: direct injection (GDI)	2008	700	10.8	2008	1000	10.8	N/A	N/A	N/A
Gasoline Engine IV: hybrid electric powertrain	2010	6000	405	2010	8000	40.5	N/A	N/A	N/A
Weight Reduction I: high strength lightweight materials	2010	1300	4.5	20070	2000	4.5	2005	2000	9.0
Diesel Emission-NO_x I: exhaust reciculation, timing retard, selective catalytic reduction	2002	250	-3.0	2003	400	-3.0	2003	500	-0.3
Diesel Emissions-NOx II: nitrogen enriched combustion air	2003	500	-0.5	2003	700.	-0.5	2003	750	-0.5
Diesel Emissions - NOx III: non-thermal plasma catalyst	2007	1000	-1.0	2006	1200	-1.0	2007	1250	-1.0
Diesel Emissions - NOx IV: NOx absorber system	2007	1500	-2.0	2006	2000	-2.0	2007	2500	-2.0
Diesel Emission - PM I: oxidation catalyst	2002	150	-0.5	2002	200	-0.5	2002	250	-0.5
Diesel Emission - PM II: catalytic particulate filter	2006	1000	-1.0	2006	1250	-2.0	2006	1500	-1.0
Diesel Emission - HC/CO I: oxidation catalyst	2002	150	-0.5	2002	200	-0.5	2002	250	-0.5
Diesel Emission - HC/CO II: closed crankcase catalyst	2005	50	0.0	2005	65	0.0	2005	75	0.0
Gasoline Emission - PM I: Improved oxidation catalyst	2005	250	-0.3	2005	350	-0.3	N/A	N/A	N/A
Gasoline Emission - NOx I: EGR/spark retard	2002	25	-1.0	2002	25	-1.0	N/A	N/A	N/A
Gasoline Emission - NOx II: oxygen sensors	2003	75	0.0	2003	75	0.0	N/A	N/A	N/A
Gasoline Emission - NOx III: secondary air/closed loop system	2008	50	0.0	2008	50	0.0	N/A	N/A	N/A
Gasoline Emission - HC/CO I: oxygen sensors	2003	75	0.0	2003	75	0.0	N/A	N/A	N/A
Gasoline Emission - HC/CO II: evap. canister w/improved vaccum, materials, and connectors	2003	50	0.0	2003	50	0.0	N/A	N/A	N/A
Gasolline Emission - HC/CO III: oxidatio catalyst	2005	250	-0.3	2005	350	-0.3	N/A	N/A	N/A

Table 7.18. Low Technology matrix for freight trucks

Technology Type	Medium Light Trucks			Medium Heavy Trucks			Heavy Trucks		
	Introduction Year	Capital Cost (2000$)	Incr. Fuel Econ. Improvement (%)	Introduction Year	Capital Cost (2000$)	Incr. Fuel Econ. Improvement (%)	Introduction Year	Capital Cost (2000$)	Incr. Fuel Econ. Improvement (%)
Areo dynamic I: Cab top deflector,sloping hood and cab side flares	N/A	N/A	N/A	1995	750	1.8	1995	750	1.3
Closing/covering of gap between tractor and trailer, aero dynamic bumper, underside are baffles, wheel well covers	N/A	N/A	N/A	2004	800	3.1	2005	1500	2.3
Trailer leading and trailing edge curvatures	N/A	N/A	N/A	2005	400	0.5	2005	500	0.8
Aero Dynamics IV: pneumatic blowing	N/A	N/A	N/A	N/A	N/A	N/A	2010	2500	3.0
Tires I: radials	1995	40	0.8	1995	180	0.8	1995	300	0.4
Tires II: low rolling resistance	2004	180	1.3	2005	280	3.3	2005	550	1.7
Tires III: super singles	N/A	N/A	N/A	N/A	N/A	N/A	2005	700	0.8
Tires IV: reduced rolling resistance from pneumatic blowing	N/A	N/A	N/A	N/A	N/A	N/A	2015	500	1.1
Transmission: lock-up, electronic controls, reduced friction	2005	750	1.3	2005	900	1.3	2005	1000	1.3
Diesel Engine I: turbo-charged, direct injection with better thermal management	2003	800	4.5	2004	1100	7.2	N/A	N/A	N/A
Diesel Engine II: integrated starter/alternator with idle off and limited regenerative breaking	2005	1500	4.5	2005	1200	4.5	N/A	N/A	N/A
Diesel Engine III: improved engine with lower friction, better injectors, and efficient combustion	2012	2000	7.0	2008	2000	6.2	N/A	N/A	N/A
Diesel Enginee IV: hybrid electric powertrain	2010	6000	36.0	2010	9000	36.0	N/A	N/A	N/A
Diesel Engine V: internal friction reduction - improved lubricants and bearings	N/A	N/A	N/A	N/A	N/A	N/A	2005	500	1.8
Diesel Engine VI: increased peak cylinder pressure	N/A	NA	N/A	N/A	N/A	N/A	2006	1000	3.6
Diesel Engine VII: improved injectors and more efficient combustion	N/A	N/A	N/A	N/A	N/A	N/A	2007	1500	5.4
Diesel Engine VIII: waste heat improved thermal management	N/A	N/A	N/A	N/A	N/A	N/A	2010	2000	9.0
Gasoline Engine I: electronic fuel injection, DOHC, multiple values	2003	700	4.5	2003	1000	4.5	N/A	N/A	N/A
Gasoline Engine II: integrated starter/alternator with idle off and llimited regenerative breaking	2005	1000	4.5	2005	1200	7.2	N/A	N/A	N/A
Gasoline Engine III: direct injection (GDI)	2008	700	10.8	2008	1000	10.8	N/A	N/A	N/A
Gasoline Engine IV: hybrid electric powertrain	2010	6000	40.5	2010	800	40.5	N/A	N/A	N/A
Weight Reduction I: high strength lightweight materials	2010	1300	4.5	2010	2000	4.5	2010	2000	9.0
Diesel Emission-NOx 1: exhaust recirculation, timing retard, selective catalytic reduction	2002	250	-5.0	2003	400	-5.0	2003	500	-5.0
Diesel Emissions - NOx II: nitrogen enriched combustion air	2003	500	-0.5	2003	700	-0.5	2003	750	-0.5
Diesel Emissions - NOx III: non-thermal plasma catalyst	2007	1000	-7.0	2006	1200	-2.0	2007	1520	-2.0
Diesel Emissions - NOx IV: NOx absorber system	2007	1500	-4.0	2006	2000	-4.0	2007	2500	-4.0
Diesel Emission - PM I: oxidation catalyst	2002	150	-0.5	2002	200	-0.5	2002	250	-0.5
Diesel Emission - PM II: catalytic particulate filter	2006	1000	-2.0	2006	1250	-3.0	2006	1500	-2.0
Diesel Emission - HC/CO I: oxidation catalyst	2002	150	-0.5	2002	200	-0.5	2002	250	-0.5
Diesel Emission - HC/CO II: closed crankcase system	2005	50	0.0	2005	65	0.0	2005	75	0.0
Gasoline Emission - PM I: improved oxidation catalyst	2005	250	-0.3	2005	350	-0.3	N/A	N/A	N/A
Gasoline Emission - NOx I: EGR/spark retard	2002	25	-2.0	2002	25	-2.0	N/A	N/A	N/A
Gasoline Emission - NOx II: oxygen sensors	2003	75	0.0	2003	75	0.0	N/A	N/A	N/A
Gasoline Emission - NOx III: secondary air/closed loop system	2008	50	0.0	2008	50	0.0	N/A	N/A	N/A
Gasoline Emission - HC/CO I: oxygen sensors	2003	75	0.0	2003	75	0.0	N/A	N/A	N/A
Gasoline emission - HC/CO II: evap. canister w/improved vaccum,materials, and connectors	2003	50	0.0	2003	80	0.0	N/A	N/A	N/A
Gasoline Emission - HC/CO III: oxidation catalyst	2005	250	-0.3	2005	350	-0.3	N/A	N/A	N/A

Table 7.19. High technology matrix for air travel

Technology	Introduction Year	Fractional Efficiency Improvement	Jet Fuel Trigger Price (87$/gal)
Technology #1	2008	0.03	1.34
Technology #2	2014	0.07	1.34
Technology #3	2015	0.11	1.34
Technology #4	2020	0.15	1.34
Technology #5	2025	0.22	1.34
Technology #6	2018	0.20	1.34
Technology #7	2025	0.08	1.00
Technology #8	2020	0.10	0.00

Source: Jet Information Services, 2009 World Jet Inventory, data tables (2009). Energy Information Administration, Transportation Sector Model of the National Energy Modeling System, Model Documentation 2010, DOE/EIA-M070(2010), (Washington, DC, 2010).

Table 7.20. Low technology matrix for air travel

Technology	Introduction Year	Fractional Efficiency Improvement	Jet Fuel Trigger Price (87$/gal)
Technology #1	2013	0.04	1.34
Technology #2	2019	0.07	1.34
Technology #3	2025	0.11	1.34
Technology #4	2030	0.15	1.34
Technology #5	2018	0.20	1.34

Source: Jet Information Services, 2009 World Jet Inventory, data tables (2009). Energy Information Administration, Transportation Sector Model of the National Energy Modeling System, Model Documentation 2010, DOE/EIA-M070(2010), (Washington, DC, 2010).

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[26] U.S. Department of Transportation, Federal Railroad Administration, “1989 Carload Waybill

Statistics; Territorial Distribution, Traffic and Revenue by Commodity Classes,” (September 1991 and Prior issues).

[27] Energy Information Administration, op. cit., Note 15.

[28] Army Corps of Engineers, Waterborne Commerce of the United States, (Waterborne Statistics Center: New Orleans, LA, 1993).

Notes and sources

[29] Energy Information Administration, op. cit., Note 15.

[30] Bureau of Transportation Statistics, Office of Airline Information, Air Carrier Summary Data (Form 41, Schedules T-1 and T-2), (2009). http://www.transtats.bts.gov/DataIndex.asp; link: Air Carrier Summary Data (Form 41 and 298C Summary Data).

[31] Bureau of Transportation Statistics, op. cit., Note 30.

[32] U.S. Department of Transportation, Federal Aviation Administration, Airport Capacity Benchmark Report, 2004 (2004).

[33] Jet Information Services Inc., World Jet Inventory: Year-End 2009, (December 2009).

[34] Energy Information Administration, op. cit. Note 14

[35] Energy and Environmental Analysis, Inc., "Documentation of Technologies Included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks," Prepared for the Energy Information Administration, (Arlington, VA, September 30, 2002).

[36] Vyas, A., C. Saricks, and F. Stodolsky, "Projected Effect of Future Efficiency and Emissions Improving Technologies on Fuel Consumption of Heavy Trucks," Argonne National Laboratory, (Argonne, IL, 2001).

Electricity Market Module

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The NEMS Electricity Market Module (EMM) represents the capacity planning, dispatching, and pricing of electricity. It is composed of four submodules—electricity capacity planning, electricity fuel dispatching, electricity load and demand, and electricity finance and pricing. It includes nonutility capacity and generation, and electricity transmission and trade. A detailed description of the EMM is provided in the EIA publication, *Electricity Market Module of the National Energy Modeling System 2011*, DOE/EIA-M068(2011).

Based on fuel prices and electricity demands provided by the other modules of the NEMS, the EMM determines the most economical way to supply electricity, within environmental and operational constraints. There are assumptions about the operations of the electricity sector and the costs of various options in each of the EMM submodules. This section describes the model parameters and assumptions used in EMM. It includes a discussion of legislation and regulations that are incorporated in EMM as well as information about the climate change action plan. The various electricity and technology cases are also described.

EMM regions

The supply regions used in EMM are based on the North American Electric Reliability Council regions and subregions shown in Figure 6.

Figure 6. Electricity Market Model Supply Regions

Model parameters and assumptions

Generating capacity types

The capacity types represented in the EMM are shown in Table 8.1.

Table 8.1. Generating capacity types represented in the Electricity Market Module

Capacity Type
Existing coal steam plants[1]
High Sulfur Pulverized Coal with Wet Flue Gas Desulfurization
Advanced Coal - Integrated Coal Gasification Combined Cycle
Advanced Coal with carbon sequestration
Oil/Gas Steam - Oil/Gas Steam Turbine
Combined Cycle - Conventional Gas/Oil Combined Cycle Combustion Turbine
Advanced Combined Cycle - Advanced Gas/Oil Combined Cycle Combustion Turbine
Advanced Combined Cycle with carbon sequestration
Combustion Turbine - Conventional Combustion Turbine
Advanced Combustion Turbine - Steam Injected Gas Turbine
Molten Carbonate Fuel Cell
Conventional Nuclear
Advanced Nuclear - Advanced Light Water Reactor
Generic Distributed Generation - Baseload
Generic Distributed Generation - Peak
Conventional Hydropower - Hydraulic Turbine
Pumped Storage - Hydraulic Turbine Reversible
Geothermal
Municipal Solid Waste
Biomass - Fluidized Bed
Solar Thermal - Central Tower
Solar Photovoltaic - Fixed Tilt
Wind
Wind Offshore

[1]The EMM represents 32 different types of existing coal steam plants, based on the different possible configuration of NO_x, particulate and SO_2 emission control devices, as well as future options for controlling mercury.
Source: Energy Information Administration.

New generating plant characteristics

The cost and performance characteristics of new generating technologies are inputs to the electricity capacity planning submodule (Table 8.2). These characteristics are used in combination with fuel prices from the NEMS fuel supply modules and foresight on fuel prices, to compare options when new capacity is needed. Heat rates for fossil-fueled technologies are assumed to decline linearly through 2025.

For the *AEO2011*, EIA commissioned an external consultant to develop current cost estimates for utility-scale electric generating plants [1]. A cost adjustment factor, based on the producer price index for metals and metal products, allows the overnight costs to fall in the future if this index drops, or rise further if it increases.

The overnight costs shown in Table 8.2 represented the estimated cost of building a plant in a typical region of the country. Differences in plant costs due to regional distinctions are calculated by applying regional multipliers. Regional multipliers by technology were also updated for *AEO2011* based on regional costs estimates developed by the consultant. The regional variations account for multiple factors, such as differences in terrain, weather, population, and labor wages. The base overnight cost is multiplied by a project contingency factor and a technological optimism factor (described later in this chapter), resulting in the total construction cost for the first-of-a-kind unit used for the capacity choice decision.

Table 8.2 Cost and performance characteristics of new central station electricity generating technologies

Technology	Online Year[1]	Size (mW)	Lead time (years)	Base Overnight Cost in 2010 (2009 $/kW)	Contingency Factors: Project Contingency Factor[2]	Contingency Factors: Technological Optimism Factor[3]	Total Overnight Cost in 2010[4] (2009 $/kW)	Variable O&M[5] (2009 $/MWh)	Fixed O&M (2009$/kW)	Heatrate[6] in 2010 (Btu/kWhr)	nth-of-a-kind Heatrate (Btu/kWhr)
Scrubbed Coal New[7]	2014	1300	4	2,625	1.07	1.00	2,809	4.20	29.31	8,800	8,740
Integrated Coal-Gasification Comb Cycle (IGCC)7	2014	1200	4	2,974	1.07	1.00	3,182	6.79	58.52	8,700	7,450
IGCC with carbon sequestration	2016	520	4	4,797	1.07	1.03	5,287	8.83	68.47	10,700	8,307
Conv Gas/Oil Comb Cycle	2013	540	3	921	1.05	1.00	967	3.37	14.22	7,050	6,800
Adv Gas/Oil Comb Cycle (CC)	2013	400	3	917	1.08	1.00	991	3.07	14.44	6,430	6,333
Adv CC with carbon sequestration	2016	340	3	1,813	1.08	1.04	2,036	6.37	29.89	7,525	7,493
Conv Comb Turbine[8]	2012	85	2	916	1.05	1.00	961	8.15	9.75	10,745	10,450
Adv Comb Turbine	2012	210	2	626	1.05	1.00	658	6.90	14.52	9,750	8,550
Fuel Cells	2013	10	3	5,846	1.05	1.10	6,752	0.00	345.80	9,500	6,960
Adv Nuclear	2016	2236	6	4,567	1.10	1.05	5,275	2.00	87.69	10,453	10,453
Distributed Generation - Base	2013	2	3	1,349	1.05	1.00	1,416	7.37	16.58	9,050	8,900
Distributed Generation - Peak	2012	1	2	1,620	1.05	1.00	1,701	7.37	16.58	10,069	9,880
Biomass	2014	50	4	3,395	1.07	1.02	3,724	6.94	99.30	13,500	13,500
Geothermal[7,9]	2011	50	4	2,364	1.05	1.00	2,482	9.52	107.27	30,000	30,000
MSW - Landfill Gas	2011	50	3	7,698	1.07	1.00	8,237	8.23	369.28	13,648	13,648
Conventional Hydropower[9]	2014	500	4	2,019	1.10	1.00	2,221	2.42	13.55	9,854	9,854
Wind	2011	100	3	2,251	1.07	1.00	2,409	0.00	27.73	9,854	9,854
Wind Offshore	2014	400	4	4,404	1.10	1.25	6,056	0.00	86.98	9,854	9,854
Solar Thermal[7]	2013	100	3	4,333	1.07	1.00	4,636	0.00	63.23	9,854	9,854
Photovoltaic[7,10]	2012	150	2	4,474	1.05	1.00	4,697	0.00	25.73	9,854	9,854

[1]Online year represents the first year that a new unit could be completed, given an order date of 2010. For wind, geothermal and landfill gas, the online year was moved earlier to acknowledge the significant market activity already occuring in anticipation of the expiration of the Production Tax Credit.

[2]A contingency allowance is defined by the American Association of Cost Engineers as the "specific provision for unforeseeable elements of costs within a defined project scope; particularly important where previous experience has shown that unforeseeable events which will increase costs are likely to occur"

[3]The technological optimism factor is applied to the first four units of a new, unproven design, it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.

[4]Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2010.

[5]O&M = Operations and maintenance.

[6]For hydro, wind, and solar technologies, the heatrate shown represents the average heatrate for conventional thermal generation as of 2009. This is used for purposes of calculating primary energy consumption displaced for these resources, and does not imply an estimate of their actual energy conversion efficiency.

[7]Capital costs are shown before investment tax credits are applied.

[8]Combustion turbine units can be built by the model prior to 2012 if necessary to meet a given region's reserve margin.

[9]Because geothermal and hydro cost and performance characteristics are specific for each site, the table entries represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located.

[10]Costs and capacities are expressed in terms of net AC power available to the grid for the installed capacity.

Sources: For the *AEO2011* cycle, EIA commissioned an external consultant to develop current cost estimates for utility-scale electric generating plants. This report can be found at http://www.eia.gov/oiaf/beck_plantcosts/index.html. Site specific costs for geothermal were provided by the National Energy Renewable Laboratory, "Updated U.S. Geothermal Supply Curve", February 2010.

Technological optimism and learning

Overnight costs for each technology are calculated as a function of regional construction parameters, project contingency, and technological optimism and learning factors.

The technological optimism factor represents the demonstrated tendency to underestimate actual costs for a first-of-a-kind, unproven technology. As experience is gained (after building 4 units) the technological optimism factor is gradually reduced to 1.0.

The learning function in NEMS is determined at a component level. Each new technology is broken into its major components, and each component is identified as revolutionary, evolutionary or mature. Different learning rates are assumed for each component, based on the level of experience with the design component (Table 8.3). Where technologies use similar components, these components learn at the same rate as these units are built. For example, it is assumed that the underlying turbine generator for a combustion turbine, combined cycle and integrated coal-gasification combined cycle unit is basically the same. Therefore construction of any of these technologies would contribute to learning reductions for the turbine component.

The learning function has the nonlinear form:

$$OC(C) = a{*}C^{-b},$$

where C is the cumulative capacity for the technology component.

Table 8.3. Learning parameters for new generating technology components

Technology Component	Period 1 Learning Rate (LR1)	Period 2 Learning Rate(LR2)	Period 3 Learning Rate (LR3)	Period 1 Doublings	Period 2 Doublings	Minimum Total Learning by 2025
Pulverized Coal	-	-	1%	-	-	5%
Combustion Turbine - conventional	-	-	1%	-	-	5%
Combustion Turbine - advanced	-	10%	1%	-	5	10%
HRSG[1]	-	-	1%	-	-	5%
Gasifier	-	10%	1%	-	5	10%
Carbon Capture/Sequestration	20%	10%	1%	3	5	20%
Balance of Plant - IGCC	-	-	1%	-	-	5%
Balance of Plant - Turbine	-	-	1%	-	-	5%
Balance of Plant - Combined Cycle	-	-	1%	-	-	5%
Fuel Cell	20%	10%	1%	3	5	20%
Advanced Nuclear	5%	3%	1%	3	5	10%
Fuel prep - Biomass	20%	10%	1%	3	5	20%
Distributed Generation - Base	-	5%	1%	-	5	10%
Distributed Generation - Peak	-	5%	1%	-	5	10%
Geothermal	-	8%	1%	-	5	10%
Municipal Solid Waste	-	-	1%	-	-	5%
Hydropower	-	-	1%	-	-	5%
Wind	-	-	1%	-	-	1%
Wind Offshore	20%	10%	1%	3	5	20%
Solar Thermal	20%	10%	1%	3	5	20%
Solar PV	15%	8%	1%	3	5	20%

[1]HRSG = Heat Recovery Steam Generator

Note: Please see the text for a description of the methodology for learning in the Electricity Market Module.

Source: Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis.

The progress ratio (pr) is defined by speed of learning (e.g., how much costs decline for every doubling of capacity). The reduction in capital cost for every doubling of cumulative capacity (LR) is an exogenous parameter input for each component (Table 8.3). The progress ratio and LR are related by:

$pr = 2^{-b} = (1 - LR)$

The parameter "b" is calculated from the second equality above (b =-(ln(1-LR)/ln(2)). The parameter "a" is computed from initial conditions, i.e.

$a = OC(C_0)/C_0^{-b}$

where C_0 is the initial cumulative capacity. Once the rates of learning (LR) and the cumulative capacity (C_0) are known for each interval, the parameters (a and b) can be computed. Three learning steps were developed, to reflect different stages of learning as a new design is introduced into the market. New designs with a significant amount of untested technology will see high rates of learning initially, while more conventional designs will not have as much learning potential. Costs of all design components are adjusted to reflect a minimal amount of learning, even if new capacity additions are not projected. This represents cost reductions due to future international development or increased research and development.

Once the learning rates by component are calculated, a weighted average learning factor is calculated for each technology. The weights are based on the share of the initial cost estimate that is attributable to each component (Table 8.4). For technologies that do not share components, this weighted average learning rate is calculated exogenously, and input as a single component. These technologies may still have a mix of revolutionary components and more mature components, but it is not necessary to include this detail in the model unless capacity from multiple technologies would contribute to the component learning.

Table 8.5 shows the capacity credit toward component learning for the various technologies. It was assumed that for all combined-cycle technologies, the turbine unit contributed two-thirds of the capacity, and the steam unit one-third. Therefore, building one gigawatt of gas combined cycle would contribute 0.67 gigawatts toward turbine learning, and 0.33 gigawatts toward steam learning. Components that do not contribute to the capacity of the plant, such as the balance of plant category, receive 100 percent capacity credit for any capacity built with that component. For example, when calculating capacity for the "Balance of plant - CC" component, all combined cycle capacity would be counted 100 percent, both conventional and advanced.

Table 8.4. Component cost weights for new technologies

Technology	Pulverized Coal	Combustion Turbine-conventional	Combustion Turbine-advanced	HRSG	Gasifier	Carbon Capture/Sequestration	Balance of Plant-IGCC	Balance of Plant-Turbine	Balance of Plant-Combined Cycle	Fuelprep Biomass
Integrated Coal-Gasification Comb Cycle (IGCC)	0%	0%	15%	20%	41%	0%	24%	0%	0%	0%
IGCC with carbon sequestration	0%	0%	10%	15%	30%	30%	15%	0%	0%	0%
Conv Gas/Oil Comb Cycle	0%	30%	0%	40%	0%	0%	0%	0%	30%	0%
Adv Gas/Oil Comb Cycle (CC)	0%	0%	30%	40%	0%	0%	0%	0%	30%	0%
Adv CC with carbon sequestration	0%	0%	20%	25%	0%	40%	0%	0%	15%	0%
Conv Comb Turbine	0%	50%	0%	0%	0%	0%	0%	50%	0%	0%
Adv Comb Turbine	0%	0%	50%	0%	0%	0%	0%	50%	0%	0%
Biomass	50%	0%	0%	0%	0%	0%	0%	0%	0%	50%

Note: All unlisted technologies have a 100% weight with the corresponding component. Components are not broken out for all technologies unless there is overlap with other technologies.
HRSG = Heat Recovery Steam Generator.
Source: Market Based Advanced Coal Power Systems, May 1999, DOE/FE-0400.

Table 8.5. Component capacity weights for new technologies

Technology	Pulverized Coal	Combustion Turbine-conventional	Combustion Turbine-advanced	HRSG	Gasifier	Carbon Capture/ Sequestration	Balance of Plant-IGCC	Balance of Plant-Turbine	Balance of Plant-Combined Cycle	Fuelprep Biomass
Integrated Coal-Gasification Comb Cycle (IGCC)	0%	0%	67%	33%	100%	0%	100%	0%	0%	0%
IGCC with carbon sequestration	0%	0%	67%	33%	100%	100%	100%	0%	0%	0%
Conv Gas/Oil Comb Cycle	0%	67%	0%	33%	0%	0%	0%	0%	100%	0%
Adv Gas/Oil Comb Cycle (CC)	0%	0%	67%	33%	0%	0%	0%	0%	100%	0%
Adv CC with carbon sequestration	0%	0%	67%	33%	0%	100%	0%	0%	100%	0%
Conv Comb Turbine	0%	100%	0%	0%	0%	0%	0%	100%	0%	0%
Adv Comb Turbine	0%	0%	100%	0%	0%	0%	0%	100%	0%	0%
Biomass	50%	0%	0%	0%	0%	0%	0%	0%	0%	100%

HRSG = Heat Recovery Steam Generator.
Source: U.S. Energy Information Administration, Office of Electricity, coal, Nuclear and Renewables Analysis.

Distributed generation

Distributed generation is modeled in the end-use sectors (as described in the appropriate chapters) as well as in the EMM. This section describes the representation of distributed generation in the EMM only. Two generic distributed technologies are modeled. The first technology represents peaking capacity (capacity that has relatively high operating costs and is operated when demand levels are at their highest). The second generic technology for distributed generation represents base load capacity (capacity that is operated on a continuous basis under a variety of demand levels). See Table 8.2 for costs and performance assumptions. It is assumed that these plants reduce the costs of transmission upgrades that would otherwise be needed.

Demand storage

The electricity model includes the option to build a new demand storage technology to simulate load shifting, through programs such as smart meters. This is modeled as a new technology build, but with operating characteristics similar to pumped storage. The technology is able to decrease the load in peak slices, but must generate to replace that demand in other time slices. There is an input factor that identifies the amount of replacement generation needed, where a factor of less than 1.0 can be use to represent peak shaving rather than purely shifting the load to other time periods. This plant type is limited to operating only in the peak load slices, and for AEO2011, it is assumed that this capacity is limited to 3 percent of peak demand in each region.

Representation of electricity demand

The annual electricity demand projections from the NEMS demand modules are converted into load duration curves for each of the EMM regions (based on North American Electric Reliability Council regions and subregions) using historical hourly load data. The load duration curve in the EMM is made up of 9 time slices. First, the load data is split into three seasons, (winter - December through March, summer - June through September, and fall/spring). Within each season the load data is sorted from high to low, and three load segments are created - a peak segment representing the top 1 percent of the load, and then two off-peak segments representing the next 49 percent and 50 percent, respectively. The seasons were defined to account for seasonal variation in supply availability.

Reserve margins—the percentage of capacity required in excess of peak demand needed for unforeseeable outages—are determined within the model through an iterative approach comparing the marginal cost of capacity and the cost of unserved energy. The target reserve margin is adjusted each model cycle until the two costs converge. The resulting reserve margins from the AEO2011 Reference case range from 8 to 20 percent.

Fossil fuel-fired and nuclear steam plant retirement

Fossil-fired steam plant retirements and nuclear retirements are calculated endogenously within the model. Plants are assumed to retire when it is no longer economical to continue running them. Each year, the model determines whether the market price of electricity is sufficient to support the continued operation of existing plants. A plant is assumed to retire if the expected revenues from it are not sufficient to cover the annual going forward costs and if the overall cost of producing electricity can be lowered by building new replacement capacity. The going-forward costs include fuel, operations and maintenance costs and annual capital additions, which are plant specific and based on historical data. The average capital additions for existing plants are $8 per kilowatt (kW) for oil and gas steam plants, $16 per kW for coal plants and $21 per kW for nuclear plants (in 2009 dollars). These costs are added to the estimated costs at existing plants regardless of their age. Beyond 30 years of age an additional $6 per kW capital charge for fossil plants, and $32 per kW charge for nuclear plants is included in the retirement decision to reflect further investment to address impacts of aging. Age related cost increases are due to capital expenditures for major repairs or retrofits, decreases in plant performance, and/or increased maintenance costs to mitigate the effects of aging.

Biomass co-firing

Coal-fired power plants are assumed to co-fire with biomass fuel if it is economical. Co-firing requires a capital investment for boiler modifications and fuel handling. This expenditure ranges from about $123 to $282 per kilowatt of biomass capacity, depending on the type and size of the boiler. A coal-fired unit modified to allow co-firing can generate up to 15 percent of the total output using biomass fuel, assuming sufficient residue supplies are available. Larger units are required to pay additional transportation costs as the level of co-firing increases, due to the concentrated use of the regional supply.

Nuclear uprates

The *AEO2011* nuclear power projection assumes capacity increases at existing units. Nuclear plant operators can increase the rated capacity at plants through power uprates, which are license amendments that must be approved by the U.S. Nuclear Regulatory Commission (NRC). Uprates can vary from small (less than 2 percent) increases in capacity, which require very little capital investment or plant modification, to extended uprates of 15-20 percent, requiring significant modifications. Historically, most uprates were small, and the AEO projections accounted for them only after they were implemented and reported, but recent surveys by the NRC and EIA have indicated that more extended power uprates are expected in the near future. *AEO2011* assumes that all of those uprates approved, pending or expected by the NRC will be implemented, for a capacity increase of 3.8 gigawatts between 2010 and 2035. Table 8.6 provides a summary of projected uprate capacity additions by region. In cases where the NRC did not specifically identify the unit expected to uprate, EIA assumed the units with the lowest operating costs would be the next likely candidates for power increases.

Table 8.6 Nuclear uprates by EMM region
gigawatts

Texas Reliability Entity	0.0
Florida Reliability Coordinating Council	0.0
Midwest Relibility Council - East	0.0
Midwest Reliability Council - West	0.2
Northeast Power Coordinating Council/New England	0.1
Northeast Power Coordinating Council/NYC-Westchester	0.0
Northeast Power Cooordinating Council/Long Island	0.0
Northeast Power Coordinating Council/Upstate	0.2
Reliability*First* Corporation/East	0.4
Reliability*First* Corporation/Michigan	0.0
Reliability*First* Corporation/West	0.7
SERC Reliability Corporation/Delta	0.3
SERC Reliability Corporation/Gateway	0.1
SERC Reliability Corporation/Southeastern	0.3
SERC Reliability Corporation/Central	0.6
SERC Reliability Corporation/Virginia-Carolina	0.7
Southwest Power Pool/North	0.0
Southwest Power Pool/South	0.0
Western Electricity Coordinating Council/Southwest	0.0
Western Electricity Coordinating Council/California	0.1
Western Electricity Coordinating Council/Northwest Power Pool Area	0.2
Western Electricity Coordinating Council/Rockies	0.0
Total	3.8

Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis, based on Nuclear Regulatory Commission survey http://www.nrc.gov/reactors/operating/licensing/power-updates.html

Interregional electricity trade

Both firm and economy electricity transactions among utilities in different regions are represented within the EMM. In general, firm power transactions involve the trading of capacity and energy to help another region satisfy its reserve margin requirement, while economy transactions involve energy transactions motivated by the marginal generation costs of different regions. The flow of power from region to region is constrained by the existing and planned capacity limits as reported in the North American Electric Reliability Corporation and Western Electric Coordinating Council Summer and Winter Assessment of Reliability of Bulk Electricity Supply in North America. Known firm power contracts are obtained from NERC's Electricity Supply and Demand Database 2007. They are locked in for the term of the contract. Contracts that are scheduled to expire by 2016 are assumed not to be renewed. Because there is no information available about expiration dates for contracts that go beyond 2016, they are assumed to be phased out by 2025. For *AEO2011*, the option to add interregional transmission capacity was added to the EMM. In some cases it may be more economic to build generating capacity in a neighboring region, but additional costs to expand the transmission grid will be incurred as well. Explicitly expanding the interregional transmission capacity may also make the line available for additional economy trade.

Economy transactions are determined in the dispatching submodule by comparing the marginal generating costs of adjacent regions in each time slice. If one region has less expensive generating resources available in a given time period (adjusting for transmission losses and transmission capacity limits) than another region, the regions are assumed to exchange power.

International electricity trade

Two components of international firm power trade are represented in the EMM—existing and planned transactions, and unplanned transactions. Data on existing and planned transactions are obtained from the North American Electric Reliability Corporation's Electricity Supply and Demand Database 2007. Unplanned firm power trade is represented by competing Canadian supply with U.S. domestic supply options. Canadian supply is represented via supply curves using cost data from the Department of Energy report, "Northern Lights: The Economic and Practical Potential of Imported Power from Canada", (DOE/PE-0079). International economy trade is determined endogenously based on surplus energy expected to be available from Canada by region in each time slice. Canadian surplus energy is determined using Canadian electricity supply and demand projections from the MAPLE-C model developed for Natural Resources Canada.

Electricity pricing

Electricity pricing is forecast for 22 electricity market regions in the *AEO2011* for fully competitive, partially competitive and fully regulated supply regions. The price of electricity to the consumer comprises the price of generation, transmission, and distribution including applicable taxes. Transmission and distribution are considered to remain regulated in the AEO; that is, the price of transmission and distribution is based on the average cost. In competitive regions, an algorithm in place allows customers to compete for better rates among rate classes as long as the overall average cost is met. The price of electricity in the regulated regions consists of the average cost of generation, transmission, and distribution for each customer class. In the competitive regions, the generation component of price is based on marginal cost, which is defined as the cost of the last (or most expensive) unit dispatched. The marginal cost includes fuel, operation and maintenance, taxes, and a reliability price adjustment, which represents the value of capacity in periods of high demand. The price of electricity in the regions with a competitive generation market consists of the marginal cost of generation summed with the average costs of transmission and distribution. The price for mixed regions is a load-weighted average of the competitive price and the regulated price, based on the percent of electricity load in the region that has taken action to deregulate. In competitively supplied regions, a transition period is assumed to occur (usually over a ten-year period) from the effective date of restructuring, with a gradual shift to marginal cost pricing.

The Reference case assumes a transition to full competitive pricing in the three New York regions and in the Reliability*First* Corporation/ East region, and a 97 percent transition to competitive pricing in New England (Vermont being the only fully-regulated State in that region). Seven regions fully regulate their electricity supply including the Florida Reliability Coordinating Council, three of the SERC Reliability Corporation subregions - Southeastern (SRSE), Central (SRCE) and Virginia-Carolina (SRVC) - Southwest Power Pool/North (SPNO), and the Western Electricity Coordinating Council / Rockies (RMPA). ERCOT, the Texas Reliability Entity which in the past was considered fully competitive by 2010, now reaches only 88 percent competitive, since many cooperatives have declined to become competitive or allow competitive energy to be sold to their customers. California returned to almost fully regulated pricing in 2002, after beginning a transition to competition in 1998, with only 7 percent competitive supply sold currently in the Western Electricity Coordinating Council (WECC)/ California region. All other regions are a mix of both competitive and regulated prices.

In recent years, the move towards competition in the electricity business has led utilities to make efforts to reduce costs to improve their market position. These cost reduction efforts are reflected in utility operating data reported to the Federal Energy Regulatory Commission (FERC) and these trends have been incorporated in the *AEO2011*. Both General and Administrative (G&A) expenses and Operations and Maintenance (O&M) expenses have shown declines in recent years. The O&M declines show variation based on the plant type. A regression analysis of recent data was done to determine the trend, and the resulting function was used to project declines throughout the projection. The analysis of G&A costs used data from 1992 through 2001, which had a 15 percent overall decline in G&A costs, and a 1.8 percent average annual decline rate. The *AEO2011* projection assumes a further decline of 18 percent by 2023 based on the results of the regression analysis. The O&M cost data was available from 1990 through 2001, and showed average annual declines of 2.1 percent for all steam units, 1.8 percent for combined cycle and 1.5 percent for nuclear. The AEO2010 assumes further declines in O&M expenses for these plant types, for a total decline through 2025 of 17 percent for combined cycle, 15 percent for steam and 8 percent for nuclear.

There have been ongoing changes to pricing structures for ratepayers in competitive States since the inception of retail competition. The AEO has incorporated these changes as they have been incorporated into utility tariffs. These have included transition period rate reductions and freezes instituted by various States, and surcharges in California relating to the 2000-2001 energy crisis there. Since price freezes for most customers have ended or will end in the next year or two, a large survey of utility tariffs found that many costs related to the transition to competition were now explicitly added to the distribution portion, and sometimes the transmission portion of the customer bill regardless of whether or not the customer bought generation service from a competitive or regulated supplier. There are some unexpected costs relating to unforeseen events. For instance, as a result of volatile fuel markets, State regulators have had a hard time enticing retail suppliers to offer competitive supply to residential and smaller commercial and industrial customers. They have often resorted to procuring the energy themselves through auction or competitive bids or have allowed distribution utilities to procure the energy on the open market for their customers for a fee. For *AEO2011*, typical charges that all customers must pay on the distribution portion of their bill (depending on where they reside) include: transition charges (including persistent stranded costs), public benefits charges (usually for efficiency and renewable energy programs), administrative costs of energy procurement, and nuclear decommissioning costs. Costs added to the transmission portion of the bill include the Federally Mandated Congestion Charges (FMCC), a bill pass-through associated with the Federal Energy Regulatory Commission passage of Standard Market Design (SMD) to enhance reliability of the transmission grid and control congestion. Additional costs, not included in historical data sets have been added in adjustment factors to the transmission and distribution operations and maintenance costs, which impact the cost of both competitive and regulated electricity supply. Since most of these costs, such as transition costs, are temporary in nature, they are gradually phased out throughout the forecast. Regions found to have these added costs include the Northeast Power Coordinating Council/ New England and New York regions, the Reliability First Corporation/ East and West regions, and the WECC/ California region.

Transmission costs for the AEO are traditionally projected based on regressions of historical spending per non-coincident peak time electricity use to ensure that the model builds enough transmission infrastructure to accommodate growth in peak electricity demand. However, since spending decreased throughout the 1990s EIA has had to add in extra spending on transmission. Additions were based on several large studies, such as the Department of Energy's National Transmission Grid Study, which set out to document how much spending would be needed to keep the national grid operating efficiently. Transmission spending has in fact been increasing very recently. EIA will be monitoring transmission spending closely over the next several years and updates will be made as new information becomes available.

Fuel price expectations

Capacity planning decisions in the EMM are based on a life cycle cost analysis over a 30-year period. This requires foresight assumptions for fuel prices. Expected prices for coal, natural gas and oil are derived using rational expectations, or 'perfect foresight'. In this approach, expectations for future years are defined by the realized solution values for these years in a prior run. The expectations for the world oil price and natural gas wellhead price are set using the resulting prices from a prior run. The markups to the delivered fuel prices are calculated based on the markups from the previous year within a NEMS run. Coal prices are determined using the same coal supply curves developed in the Coal Market Module. The supply curves produce prices at different levels of coal production, as a function of labor productivity, and costs and utilization of mines. Expectations for each supply curve are developed in the EMM based on the actual demand changes from the prior run throughout the projection horizon, resulting in updated mining utilization and different supply curves.

The perfect foresight approach generates an internally consistent scenario for which the formation of expectations is consistent with the projections realized in the model. The NEMS model involves iterative cycling of runs until the expected values and realized values for variables converge between cycles.

Nuclear fuel prices

Nuclear fuel prices are calculated through an offline analysis which determines the delivered price to generators in mills per kilowatthour. To produce reactor grade uranium, the uranium (U308) must first be mined, and then sent through a conversion process to prepare for enrichment. The enrichment process takes the fuel to a given purity of U-235, typically 3-5 percent for commercial reactors in the United States. Finally, the fabrication process prepares the enriched uranium for use in a specific type of reactor core. The price of each of the processes is determined, and the prices are summed to get the final price of the delivered fuel. The one mill per kilowatthour charge that is assessed on nuclear generation to go to the DOE's Nuclear Waste Fund is also included in the final nuclear price. The analysis uses forecasts from Energy Resources International for the underlying uranium prices.

Legislation and regulations

Clean Air Act Amendments of 1990 (CAAA90) and Clean Air Interstate Rule (CAIR)

The Clean Air Interstate Rule is a cap-and-trade program promulgated by the EPA in 2005 to reduce SO2 and NOx emissions in order to help States meet their National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter, and to further emissions reductions already achieved through earlier programs. On July 11, 2008 the U.S. District Court of Appeals overturned CAIR. However, on December 23, 2008, the Court of Appeals issued a new ruling that allowed CAIR to remain in effect while EPA determines the appropriate modifications to address the original objections. Therefore, CAIR is modeled explicitly in the *AEO2011*.

As specified in the CAAA90, EPA has developed a two-phase nitrogen oxide (NOx) program, with the first set of standards for existing coal plants applied in 1996 while the second set was implemented in 2000. Dry bottom wall-fired, and tangential fired boilers, the most common boiler types, referred to as Group 1 Boilers, were required to make significant reductions beginning in 1996 and further reductions in 2000. Relative to their uncontrolled emission rates, which range roughly between 0.6 and 1.0 pounds per million Btu, they are required to make reductions between 25 and 50 percent to meet the Phase I limits and further reductions to meet the Phase II limits. The EPA did not impose limits on existing oil and gas plants, but some states have additional NOx regulations. All new fossil units are required to meet standards. In pounds per million Btu, these limits are 0.11 for conventional coal, 0.02 for advanced coal, 0.02 for combined cycle, and 0.08 for combustion turbines. These NOx limits are incorporated in EMM.

In addition, the EPA has issued rules to limit the emissions of NOx, specifically calling for capping emissions during the summer season in 22 Eastern and Midwestern states. After an initial challenge, these rules have been upheld, and emissions limits have been finalized for 19 states and the District of Columbia (Table 8.7). Within EMM, electric generators in these 19 states must comply with the limit either by reducing their own emissions or purchasing allowances from others who have more than they need.

Table 8.7. Summer Season NOx Emissions Budgets for 2004 and Beyond
thousand tons per season

State	Emissions Cap
Alabama	29.02
Connecticut	2.65
Delaware	5.25
District of Columbia	0.21
Illinois	32.37
Indiana	47.73
Kentucky	36.50
Maryland	14.66
Massachusetts	15.15
Michigan	32.23
New Jersey	10.25
New York	31.04
North Carolina	31.82
Ohio	48.99
Pennsylvania	47.47
Rhode Island	1.00
South Carolina	16.77
Tennessee	25.81
Virginia	17.19
West Virginia	26.86

Source: U.S. Environmental Protection Agency, Federal Register, Vol. 65, number 42 (March 2, 2002) pages 11222-11231.

The costs of adding flue gas desulfurization equipment (FGD) to remove sulfur dioxide (SO2) and selective catalytic reduction (SCR) equipment to remove nitrogen oxides (NOx) are given below for 300, 500, and 700-megawatt coal plants. FGD units are assumed to remove 95 percent of the SO2, while SCR units are assumed to remove 90 percent of the NOx. The costs per megawatt of capacity decline with plant size and are shown in Table 8.8.

Table 8.8. Coal plant retrofit costs
2009 dollars

Coal Plant Size (MW)	FGD Capital Costs ($/KW)	SCR Capital Costs ($/KW)
300	556	179
500	464	161
700	428	159

Documentation for EPA Base Case v4.10 using the Integrated Planning Model, August 2010, EPA Contract EP-W-08-018.

Mercury regulation

The Clean Air Mercury Rule set up a national cap-and-trade program with emission limits set to begin in 2011. This rule was vacated in February, 2008 and therefore is not included in the *AEO2011*. However, many States had already begun adopting more stringent regulations calling for the application of the best available control technology on all electricity generating units of a certain capacity. After the court's decision, more States imposed their own regulations. Because State laws differ, a rough estimate was created that generalized the various State programs into a format that could be used in NEMS. The EMM allows plants to alter their configuration by adding equipment, such as an SCR to remove NOx or an SO2 scrubber. They can also add activated carbon injection systems specifically designed to remove mercury. Activated carbon can be injected in front of existing particulate control devices or a supplemental fabric filter can be added with activated carbon injection capability.

The equipment to inject activated carbon in front of an existing particulate control device is assumed to cost approximately $6 (2009 dollars) per kilowatt of capacity, while the cost of a supplemental fabric filter with activated carbon injection (often referred as a COPAC unit) is approximately $77 per kilowatt of capacity [2]. The amount of activated carbon required to meet a given percentage removal target is given by the following equations [3].

For a unit with a CSE, using subbituminous coal, and simple activated carbon injection:

- Hg Removal (%) = 65 - (65.286 / (ACI + 1.026))

For a unit with a CSE, using bituminous coal, and simple activated carbon injection:

- Hg Removal (%) = 100 - (469.379 / (ACI + 7.169))

For a unit with a CSE, and a supplemental fabric filter with activated carbon injection:

- Hg Removal (%) = 100 - (28.049 / (ACI + 0.428))

For a unit with a HSE/Other, and a supplemental fabric filter with activated carbon injection:

- Hg Removal (%) = 100 - (43.068 / (ACI + 0.421))

ACI = activated carbon injected in pounds per million actual cubic feet.

Power plant mercury emissions assumptions

The EMM represents 35 coal plant configurations and assigns a mercury emissions modification factor (EMF) to each configuration. Each configuration represents different combinations of boiler types, particulate control devices, sulfur dioxide (SO_2) control devices, nitrogen oxide (NO_x) control devices, and mercury control devices. An EMF represents the amount of mercury that was in the fuel that remains after passing through all the plant's systems. For example, an EMF of 0.60 means that 40 percent of the mercury that was in the fuel is removed by various parts of the plant. Table 8.9 provides the assumed EMFs for existing coal plant configurations without mercury specific controls.

Table 8.9. Mercury emission modification factors

Configuration			EIA EMFs			EPA EMFs		
SO_2 Control	Particulate Control	NO_x Control	Bit Coal	Sub Coal	Lignite Coal	Bit Coal	Sub Coal	Lignite Coal
None	BH	—	0.11	0.27	0.27	0.11	0.26	1.00
Wet	BH	None	0.05	0.27	0.27	0.03	0.27	1.00
Wet	BH	SCR	0.10	0.27	0.27	0.10	0.15	0.56
Dry	BH	—-	0.05	0.75	0.75	0.05	0.75	1.00
None	CSE	—-	0.64	0.97	0.97	0.64	0.97	1.00
Wet	CSE	None	0.34	0.73	0.73	0.34	0.84	0.56
Wet	CSE	SCR	0.10	0.73	0.73	0.10	0.34	0.56
Dry	CSE	—-	0.64	0.65	0.65	0.64	0.65	1.00
None	HSE/Oth	—-	0.90	0.94	0.94	0.90	0.94	1.00
Wet	HSE/Oth	None	0.58	0.80	0.80	0.58	0.80	1.00
Wet	HSE/Oth	SCR	0.42	0.76	0.76	0.10	0.75	1.00
Dry	HSE/Oth	—-	0.60	0.85	0.85	0.60	0.85	1.00

Notes: SO_2 Controls - Wet = Wet Scrubber and Dry = Dry Scrubber, Particulate Controls, BH - fabric filter/baghouse. CSE = cold side electrostatic precipitator, HSE = hot side electrostatic precipitator, NO_x Controls, SCR = selective catalytic reduction, — = not applicable, Bit = bituminous coal, Sub = subbituminous coal. The NO_x control system is not assumed to enhance mercury removal unless a wet scrubber is present, so it is left blank in such configurations.
Sources: EPA, EMFs. http://www.epa.gov/clearskies/technical.html EIA EMFs not from EPA: Lignite EMFs, Mercury Control Technologies for Coal-Fired Power Plants, presented by the Office of Fossil Energy on July 8, 2003. Bituminous coal mercury removal for a Wet/HSE/Oth/SCR configured plant, Table EMF1, Analysis of Mercury Control Cost and Performance, Office of Fossil Energy & National Energy Technology Laboratory, U.S. Department of Energy, January 2003, Washington, DC.

Planned SO_2 ccrubber and NO_x control equipment additions

In recent years, in response to state emission reduction programs and compliance agreements with the Environmental Protection Agency, some companies have announced plans to add scrubbers to their plants to reduce sulfur dioxide and particulate emissions. Where firm commitments appear to have been made these plans have been represented in NEMS. Based on EIA analysis of announced plans, 31.4 gigawatts of capacity are assumed to add these controls (Table 8.10). The greatest number of retrofits is expected to occur in the Midwestern States, where there is a large base of coal capacity impacted by the SO_2 limit in CAIR, as well as in the Southeastern Electric Reliability Council because of the Clean Smokestacks bill passed by the North Carolina General Assembly.

Table 8.10 Planned SO_2 scrubber additions by EMM region
gigawatts

Texas Reliability Entity	0.0
Florida Reliability Coordinating Council	1.4
Midwest Relibility Council - East	0.0
Midwest Reliability Council - West	1.1
Northeast Power Coordinating Council/New England	0.0
Northeast Power Coordinating Council/NYC-Westchester	0.0
Northeast Power Cooordinating Council/Long Island	0.0
Northeast Power Coordinating Council/Upstate	0.2
Reliability*First* Corporation/East	4.0
Reliability*First* Corporation/Michigan	0.8
Reliability*First* Corporation/West	6.2
SERC Reliability Corporation/Delta	0.0
SERC Reliability Corporation/Gateway	3.7
SERC Reliability Corporation/Southeastern	8.5
SERC Reliability Corporation/Central	2.5
SERC Reliability Corporation/Virginia-Carolina	2.9
Southwest Power Pool/North	0.0
Southwest Power Pool/South	0.0
Western Electricity Coordinating Council/Southwest	0.0
Western Electricity Coordinating Council/California	0.0
Western Electricity Coordinating Council/Northwest Power Pool Area	0.0
Western Electricity Coordinating Council/Rockies	0.0
Total	31.4

Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis, based on public announcements and reports to Form EIA-860, "Annual Electric Generator Report".

Companies are also announcing plans to retrofit units with controls to reduce NO_x emissions to comply with emission limits in certain states. In the Reference case planned post-combustion control equipment amounts to 17.9 gigawatts of selective catalytic reduction (SCR).

Carbon capture and sequestration retrofits

Although a federal greenhouse gas program is not assumed in the *AEO2011* Reference case, the EMM includes the option of retrofitting existing coal plants for carbon capture and sequestration (CCS). This option is important when considering alternate scenarios that do constrain carbon emissions. The modeling structure for CCS retrofits within the EMM was developed by the National Energy Technology Laboratory[4] and uses a generic model of retrofit costs as a function of basic plant characteristics (such as heatrate). For *AEO2011*, the costs were adjusted upwards to be consistent with costs of new CCS technologies. The CCS retrofits are assumed to remove 90% of the carbon input. The addition of the CCS equipment results in a capacity derate of around 30% and reduced efficiency of 43% at the existing coal plant. The costs depend on the size and efficiency of the plant, with the capital costs ranging from $1,100 to $1,600 per kilowatt. It was assumed that only plants greater than 500 megawatts and with heatrates below 12,000 BTU per kilowatthour would be considered for CCS retrofits.

Energy Policy Acts of 1992 (EPACT92) and 2005 (EPACT05)

The provisions of the EPACT92 include revised licensing procedures for nuclear plants and the creation of exempt wholesale generators (EWGs). The EPACT05 provides a 20-percent investment tax credit for Integrated Coal-Gasification Combined Cycle capacity and a 15-percent investment tax credit for other advanced coal technologies. These credits are limited to 3 gigawatts in both cases. It also contains a production tax credit (PTC) of 1.8 cents (nominal) per kilowatthour for new nuclear capacity beginning operation by 2020. This PTC is specified for the first 8 years of operation, is limited to $125 million (per gigawatt) annually, and is limited to 6 gigawatts of new capacity. However, this credit may be shared to additional units if more than 6 gigawatts are under construction by January 1, 2014. EPACT05 extended the PTC for qualifying renewable facilities by 2 years, or December 31, 2007. It also repealed the Public Utility Holding Company Act (PUHCA).

Energy Improvement and Extension Act 2008 (EIEA2008)

EIEA2008 extended the PTC to qualifying wind facilities entering service by December 31, 2009. Eligibility of other facilities such as geothermal, hydroelectric, and biomass facilities, was extended through December 31, 2010.

American Recovery and Reinvestment Act (ARRA)

Updated tax credits for Renewables

ARRA further extended the expiration date for the PTC to January 1, 2013, for wind and January 1, 2014, for all other eligible renewable resources. In addition, ARRA allows companies to choose an investment tax credit (ITC) of 30 percent in lieu of the PTC and allows for a grant in lieu of this credit to be funded by the U.S. Treasury. For some technologies, such as wind, the full PTC would appear to be more valuable than the 30 percent ITC; however, the difference can be small. Qualitative factors, such as the lack of partners with sufficient tax liability, may cause companies to favor the ITC grant option. The *AEO2011* generally assumes that renewable electricity projects will claim the more favorable tax credit or grant option available to them.

Loan guarantees for renewables

ARRA provided $6 billion to pay the cost of guarantees for loans authorized by the Energy Policy Act of 2005. While most renewable projects which start construction prior to September 30, 2011 are potentially eligible for these loan guarantees, the application and approval of guarantees for specific projects is a highly discretionary process, and has thus far been limited. While the *AEO2011* includes projects that have received loan guarantees under this authority, it does not assume automatic award of the loans to potentially eligible technologies.

Support for CCS

ARRA provided $3.4 billion for additional research and development on fossil energy technologies. A portion of this funding is expected to be used to fund projects under the Clean Coal Power Initiative program, focusing on projects that capture and sequester greenhouse gases. To reflect the impact of this provision, the *AEO2011* Reference case assumes that an additional 1 gigawatt of coal capacity with CCS will be stimulated by 2017.

Smart grid expenditures

ARRA provides $4.5 billion for smart grid demonstration projects. While somewhat difficult to define, smart grid technologies generally include a wide array of measurement, communications, and control equipment employed throughout the transmission and distribution system that will enable real-time monitoring of the production, flow, and use of power from generator to consumer. Among other things, these smart grid technologies are expected to enable more efficient use of the transmission and distribution grid, lower line losses, facilitate greater use of renewables, and provide information to utilities and their customers that will lead to greater investment in energy efficiency and reduced peak load demands. The funds provided will not fund a widespread implementation of smart grid technologies, but could stimulate more rapid investment than would otherwise occur.

Several changes were made throughout the NEMS to represent the impacts of the smart grid funding provided in ARRA. In the electricity module, it was assumed that line losses would fall slightly, peak loads would fall as customers shifted their usage patterns, and customers would be more responsive to pricing signals. Historically, line losses, expressed as the percentage of electricity lost, have been falling for many years as utilities make investments to replace aging or failing equipment.

Smart grid technologies also have the potential to reduce peak demand through the increased deployment of demand response programs. In the AEO2011, it is assumed that the Federal expenditures on smart grid technologies will stimulate efforts that reduce peak demand in 2035 by 3 percent from what they otherwise would be. Load is shifted to offpeak hours, so net energy consumed remains largely constant.

FERC Orders 888 and 889

FERC has issued two related rules (Orders 888 and 889) designed to bring low cost power to consumers through competition, ensure continued reliability in the industry, and provide for open and equitable transmission services by owners of these facilities. Specifically, Order 888 requires open access to the transmission grid currently owned and operated by utilities. The transmission owners must file nondiscriminatory tariffs that offer other suppliers the same services that the owners provide for themselves. Order 888 also allows these utilities to recover stranded costs (investments in generating assets that are unrecoverable due to consumers selecting another supplier). Order 889 requires utilities to implement standards of conduct and an Open Access Same-Time Information System (OASIS) through which utilities and non-utilities can receive information regarding the transmission system. Consequently, utilities are expected to functionally or physically unbundle their marketing functions from their transmission functions.

These orders are represented in EMM by assuming that all generators in a given region are able to satisfy load requirements anywhere within the region. Similarly, it is assumed that transactions between regions will occur if the cost differentials between them make such transactions economical.

Electricity alternative cases

Fossil Technology Cost cases

The High Fossil Technology Cost case assumes that the base costs of all fossil generating technologies will remain at current costs during the projection period, with no reductions due to learning. The annual commodity cost adjustment factor is still applied as in the Reference case. (Table 8.11) Capital costs of non-fossil generating technologies are the same as those assumed in the Reference case.

In the Low Fossil Technology Cost case, capital costs, and operating costs for the fossil technologies are assumed to start 20% lower than the Reference case levels and to be 40 percent lower than Reference case levels in 2035. Since learning occurs in the Reference case, costs and performance in the low case are reduced from initial levels by more than 40 percent, across the fossil technologies. Capital costs are reduced by 43 percent to 58 percent between 2011 and 2035.

The Low and High Fossil Technology Cost cases are fully-integrated NEMS runs, allowing feedback from the end-use demand and fuel supply modules.

Nuclear Cost cases

For nuclear power plants, two nuclear cost cases analyze the sensitivity of the projections to lower and higher costs for new plants. The cost assumptions for the Low nuclear cost case reflect a 20 percent decline in initial costs and a 40 percent reduction in the capital and operating cost for the advanced nuclear technology in 2035, relative to the Reference case. Since the Reference case assumes some learning occurs regardless of new orders and construction, the Reference case already projects a 35 percent reduction in capital costs between 2011 and 2035. The Low Nuclear Cost case assumes a 51 percent reduction between 2011 and 2035. The High Nuclear Cost case assumes that base capital costs for the advanced nuclear technology do not decline from 2011 levels (Table 8.12). The capital costs are still tied to key commodity price indices, but no cost improvement from "learning-by-doing" effects is assumed.

Electricity Plant Capital Cost cases

The costs to build new power plants have risen dramatically in the past few years, driven primarily by significant increases in the costs of construction related materials, such as cement, iron, steel and copper. For the *AEO2011* Reference case, initial overnight costs for all technologies were updated to be consistent with costs estimates for 2010. A cost adjustment factor based on the projected producer price index for metals and metal products is also applied throughout the forecast, allowing the overnight costs to fall in the future if this index drops or rise further if the index increases. Although there is significant correlation between commodity prices and power plant costs, there may be other factors that influence future costs that raise the uncertainties surrounding the future costs of building new power plants. For the *AEO2011*, two additional cost cases were run which focus on the uncertainties of future plant construction costs. These cases use exogenous assumptions for the annual adjustment factors, rather than linking to the metals price index. The cases are discussed in the Issues in Focus article, "Cost Uncertanties for new Electric Power Plants." (*AEO* pages 40-42)

- In the Frozen Plant Capital Costs case, base overnight costs for all new electric generating technologies are assumed to be frozen at 2015 levels. Cost decreases due to learning can still occur. In this case, costs do decline slightly over the projection, but by 2035 are roughly 25 percent above Reference case costs for the same year.
- In the Decreasing Plant Capital Costs case, base overnight costs for all new electric generating technologies are assumed to fall more rapidly than in the Reference case. The base overnight costs are assumed to be 20 percent below the Reference case, through a reduction in the annual cost index. Costs are also assumed to decline more rapidly, so that by 2035 the cost factor is assumed to be 40 percentage points below the Reference case value.

Electricity Environmental Regulation cases

Over the next few years electricity generators will have to begin steps to comply with a large number of new environmental regulations that are currently in various stages of promulgation. The *AEO2011* Reference case does not include regulations that are still under development. However, the issues in Focus article, "Power Sector Environmental Regulations on the Horizon" (*AEO* pages 45-53) discusses the status of the different rules and examines potential impacts through a number of scenarios.

- In the Transport Mercury MACT 20 case, it is assumed that the Air Transport Rule limits on SO_2 and NO_X and a 90 percent mercury MACT are enacted. A 20 year recovery period for environmental control projects is assumed.
- In the Transport Mercury MACT 5 case, the same rules as in the first case are assumed, but a five year recovery period is used on the investments in environmental control projects.
- The Retrofit Required 20 case is designed to represent a scenario where stringent requirements are placed on air emission from coal plants. It assumes that utility boilers fall under the MACT rule, which requires all plants to install FGD scrubbers by 2020 in order to comply with acid gas reduction requirements. It also requires that all plants install SCRs in order to meet future NO_x and ozone requirements. If the investment in an FGD and SCR is not economic, then the plant is retired. Investments in retrofits are assumed recovered over a 20 year life.
- The Retrofit Required 5 case assumes the same stringent requirements as above, but uses a five year economic life for retrofits.
- The Low Gas Price Retrofit Required 20 case is identical to the Retrofit Required 20 case, but also adds an assumption of increased domestic shale gas availability and utilization rate, as in the Oil and Gas High Shale EUR case. Increased access to natural gas lowers the natural gas prices paid by the electric power sector.
- The Low Gas Price Retrofit Required 5 case assumes the same environmental requirements and lower gas prices as above, but uses a five year economic life for retrofits.

Table 8.11. Cost characteristics for fossil-fueled generating technologies: three cases

	Total Overnight Cost in 2011 (Reference) (2009$/kW)	Total Overnight Cost[1]		
		Reference (2009$/kW)	High Fossil Cost (2009$/kW)	Low Fossil Cost (2009$/kW)
Pulverized Coal	2809			
2015		2871	2894	2202
2020		2756	2838	1998
2025		2563	2697	1751
2030		2343	2499	1503
2035		2126	2304	1275
Advanced Coal	3182			
2015		3226	3278	2472
2020		3066	3215	2222
2025		2817	3055	1925
2030		2534	2833	1626
2035		2265	2610	1358
Advanced Coal with Sequestration	5287			
2015		5306	5446	4068
2020		4770	5339	3457
2025		4315	5075	2948
2030		3822	4705	2452
2035		3356	4336	2014
Conventional Combined Cycle	967			
2015		988	995	757
2020		949	976	688
2025		882	928	602
2030		806	860	517
2035		732	793	439
Advanced Gas	991			
2015		1007	1020	771
2020		962	1000	696
2025		887	951	605
2030		798	881	512
2035		714	812	428
Advanced Gas with Sequestration	2036			
2015		2040	2097	1563
2020		1804	2057	1307
2025		1626	1954	1111
2030		1430	1812	918
2035		1247	1669	748
Conventional Combustion Turbine	961			
2015		983	990	754
2020		943	970	684
2025		877	922	599
2030		802	855	515
2035		728	789	437
Advanced Combustion Turbine	658			
2015		666	677	510
2020		634	665	459
2025		581	631	396
2030	658			
2035		458	539	275

[1]Total overnight cost (including project contingency, technological optimism and learning factors, but excluding regional multipliers), for projects online in the given year.

Source: U.S. Energy Information Administration. *AEO2011* National Energy Modeling System runs: REF2011.D020911A, HCFOSS11.D020911A, LCFOSS11.D020911A

Table 8.12 Cost characteristics for advanced nuclear technology: three cases

Advanced Nuclear Technology	Overnight Cost in 2011 (Reference) (2009$/kW)	Total Overnight Cost[1] Reference (2009$/kW)	High Nuclear Cost (2009$/kW)	Low Nuclear Cost (2009$/kW)
	5275			
2015		5311	5433	4113
2020		4853	5327	3556
2025		4316	5064	2985
2030		3868	4694	2514
2035		3435	4325	2061

[1]Total overnight cost (including project contingency, technological optimism and learning factors, but excluding regional multipliers), for projects online in the given year.
Source: U.S. Energy Information Administration. AEO2011 National Energy Modeling System runs: REF2011.D020911A, HCNUC11.D020911A, LCNUC11.D020911A.

Table 8.13 Cost characteristics for new electric generating technologies: three cases
2009$/kw

		Reference		Frozen Cost Case		Decreasing Cost Case	
	Initial Cost 2011	2020	2035	2020	2035	2020	2035
Scrubbed Coal New	2809	2756	2126	2820	2675	1995	1269
Integrated Coal-Gasification Comb Cycle (IGCC)	3182	3066	2265	3136	2852	2218	1354
IGCC with carbon sequestration	5287	4770	3356	4880	4225	3451	2006
Conv Gas/Oil Comb Cycle	967	949	732	971	921	686	437
Adv Gas/Oil Comb Cycle (CC)	991	962	714	984	900	696	428
Adv CC with carbon sequestration	2036	1804	1247	1845	1572	1305	746
Conv Comb Turbine	961	943	728	965	916	683	434
Adv Comb Turbine	658	634	458	648	578	458	275
Fuel Cells	6752	6011	3777	6150	4752	4350	2255
Adv Nuclear	5275	4853	3435	4965	4322	3512	2050
Distributed Generation - Base	1416	1347	958	1378	1214	975	584
Distributed Generation - Peak	1701	1555	1124	1602	1426	1008	585
Biomass	3724	3597	2696	3681	3392	2603	1609
Geothermal	2482	2364	2546	2419	3285	1704	1486
MSW - Landfill Gas	8237	8082	6233	8269	7843	5849	3721
Conventional Hydropower	2221	2257	987	2309	1356	1191	1547
Wind	2409	2412	1941	2468	2443	1743	1158
Wind Offshore	6056	5440	3927	5567	4941	3935	2343
Solar Thermal	4636	3408	2008	3486	2527	2466	1199
Photovoltaic	4697	4056	2496	4150	3140	2935	1293

Source: U.S. Energy Information Administration. *AEO2011* National Energy Modeling System runs: AEO2011.D020911A, FRZCST11.D020911A, DECCST11.D020911A.

Notes and sources

[1] Updated Capital Cost Estimates for Electricity Generation Plants, EIA, November 2010.

[2] These costs were developed using the National Energy Technology Laboratory Mercury Control Performance and Cost Model, 1998.

[3] U.S. Department of Energy, Analysis of Mercury Control Cost and Performance, Office of Fossil Energy & National Energy Technology Laboratory, January 2003.

[4] Retrofitting Coal Fired Power Plants for Carbon Dioxide Capture and Sequestration - Exploratory Testing of NEMS for Integrated Assessments, DOE/NETL-2008/1309, P.A. Geisbrecht, January 18, 2009.

Oil and Gas Supply Module

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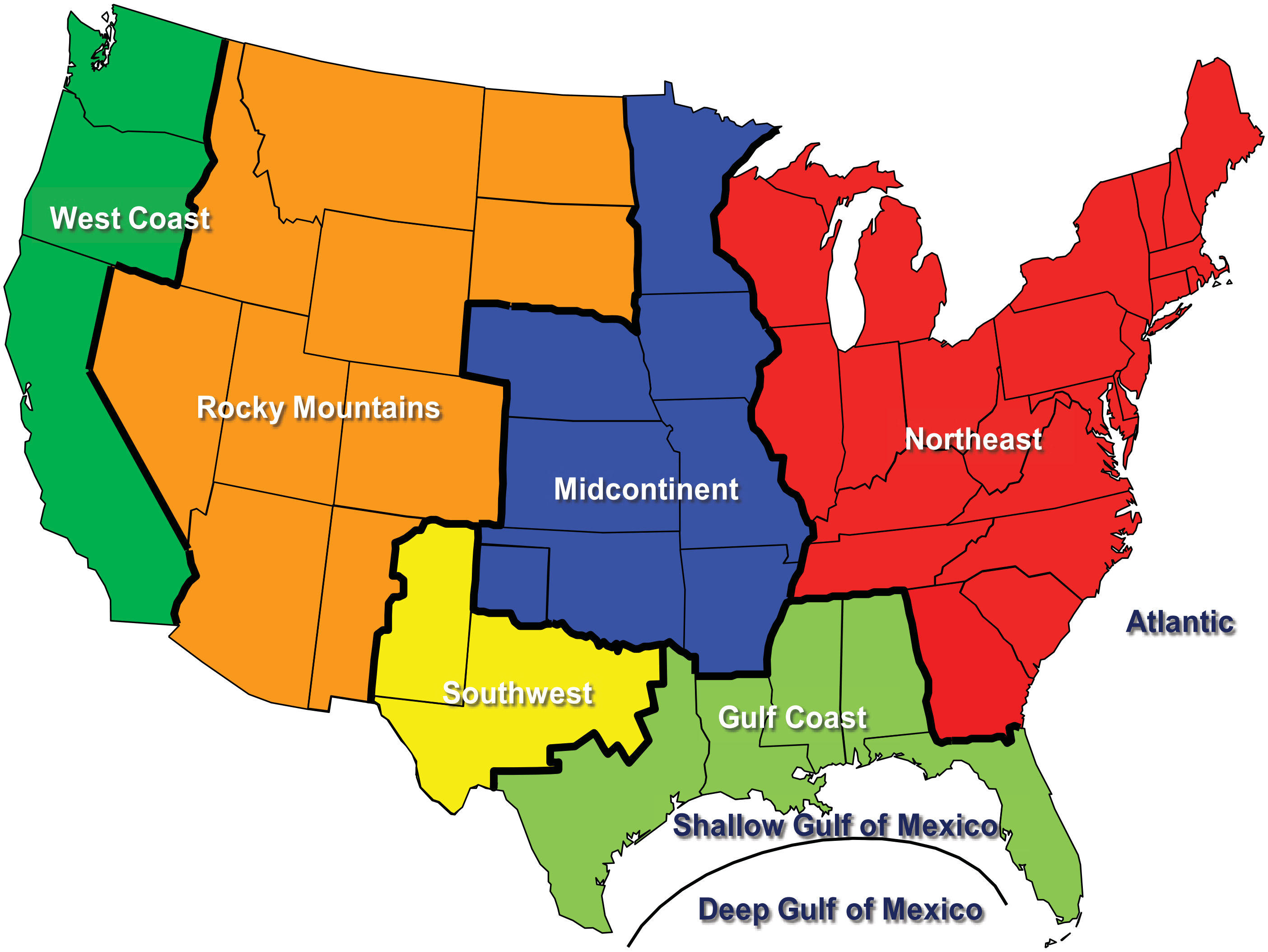
The NEMS Oil and Gas Supply Module (OGSM) constitutes a comprehensive framework with which to analyze crude oil and natural gas exploration and development on a regional basis (Figure 7). The OGSM is organized into 4 submodules: Onshore Lower 48 Oil and Gas Supply Submodule, Offshore Oil and Gas Supply Submodule, Oil Shale Supply Submodule, and Alaska Oil and Gas Supply Submodule. A detailed description of the OGSM is provided in the EIA publication, Model Documentation Report: The Oil and Gas Supply Module (OGSM), DOE/EIA-M063(2010), (Washington, DC, 2010). The OGSM provides crude oil and natural gas short-term supply parameters to both the Natural Gas Transmission and Distribution Module and the Petroleum Market Module. The OGSM simulates the activity of numerous firms that produce oil and natural gas from domestic fields throughout the United States.

Figure 7. Oil and Gas Supply Model regions



Source: U.S. Energy Information Administration, Office of Energy Analysis.

OGSM encompasses domestic crude oil and natural gas supply by several recovery techniques and sources. Crude oil recovery includes improved oil recovery processes such as water flooding, infill drilling, and horizontal continuity, as well as enhanced oil recovery processes such as CO2 flooding, steam flooding, and polymer flooding. Recovery from highly fractured, continuous zones (e.g. Austin chalk and Bakken shale formations) is also included. Natural gas supply includes resources from low-permeability tight sand formations, shale formations, coalbed methane, and other sources.

Key assumptions

Domestic oil and natural gas technically recoverable resources

Domestic oil and natural gas technically recoverable resources [1] consist of proved reserves [2], inferred reserves [3], and undiscovered technically recoverable resources [4]. OGSM resource assumptions are based on estimates of technically recoverable resources from the United States Geological Survey (USGS) and the Bureau of Ocean Energy Management (BOEM) of the Department of the Interior [5]. Supplemental adjustments to the USGS nonconventional natural gas resources are made to add some frontier plays that were not quantitatively assessed by the USGS. While undiscovered resources for Alaska are based on USGS estimates, estimates of recoverable resources are obtained on a field-by-field basis from a variety of sources including trade press. Published estimates in Tables 9.1 and 9.2 reflect the removal of intervening reserve additions between the date of the latest available assessment and January 1, 2009.

Table 9.1. Technically recoverable U.S. crude oil resources as of January 1, 2009
billion barrels

		Unproved Resources			
	Proved Reserves	Inferrred Reserves	Undiscovered Resources	Total Unproved	Total Technically Recoverable Resources
Lower 48 Onshore	12.7	50.1	51.1	101.2	113.9
Northeast	0.2	0.2	0.7	0.9	1.1
Gulf Coast	1.5	3.4	12.1	15.5	16.9
Midcontinent	1.2	7.1	5.6	12.6	13.8
Southwest	4.8	23.4	4.2	27.5	32.3
Rocky Mountain	2.5	8.9	12.3	21.2	23.6
West Coast	2.6	7.3	16.3	23.5	26.1
Lower 48 Offshore	4.3	10.3	42.7	53.0	57.4
Gulf (currently available)	3.8	9.4	32.0	41.4	45.3
Eastern/Central Gulf (unavailable until 2022)	0.0	0.0	3.7	3.7	3.7
Pacific	0.5	0.9	5.7	6.6	7.1
Atlantic	0.0	0.0	1.4	1.4	1.4
Alaska (Onshore and Offshore)	3.5	2.1	42.0	44.1	47.6
Total U.S.	20.6	62.5	135.8	198.3	218.9

Note: Crude oil resources include lease condensates but do not include natural gas plant liquids or kerogen (oil shale). Resources in areas where drilling is officially prohibited are not included in this table. The estimate of 7.3 billion barrels of crude oil resources in the Northern Atlantic, Northern and Central Pacific, and within a 50-mile buffer off the Mid and Southern Atlantic Outer Continental Shelf (OCS) is also excluded from the technically recoverable volumes because leasing is not expected in these areas by 2035.
Source: Onshore, State Offshore, and Alaska - U.S. Geological Survey (USGS); Federal OCS Offshore - Bureau of Ocean Energy Management (formerly the Minerals Management Service); Proved Reserves - U.S. Energy Information Administration. Table values reflect removal of intervening reserve additions between the date of the latest available assessment and January 1, 2009.

Lower 48 onshore

The Onshore Lower 48 Oil and Gas Supply Submodule (OLOGSS) is a play-level model used to analyze crude oil and natural gas supply from onshore lower 48 sources. The methodology includes a comprehensive assessment method for determining the relative economics of various prospects based on financial considerations, the nature of the resource, and the available technologies. The general methodology relies on a detailed economic analysis of potential projects in known fields, enhanced oil recovery projects, and undiscovered resources. The projects which are economically viable are developed subject to the availability of resource development constraints which simulate the existing and expected infrastructure of the oil and gas industries. For crude oil projects, advanced secondary or improved oil recovery techniques (e.g. infill drilling and horizontal continuity) and enhanced oil recovery (e.g. CO2 flooding, steam flooding, and polymer flooding) processes are explicitly represented. For natural gas projects, the OLOGSS represents supply from shale formations, tight sands formations, coalbed methane, and other sources.

Table 9.2. Technically recoverable U.S. natural gas resources as of January 1, 2009
trillion cubic feet

		Unproved Resources			
	Proved Reserves	Inferred Reserves	Undiscovered Resources	Total Unproved	Total Technically Recoverable Resources
Lower 48 Onshore Non Associated	220.5	1444.2	303.1	1747.3	1967.8
Tight Gas	86.0	369.4	0.0	369.4	455.4
Northeast	5.0	51.8	0.0	51.8	56.8
Gulf Coast	23.1	53.5	0.0	53.5	76.6
Midcontinent	7.1	14.0	0.0	14.0	21.1
Southwest	3.3	20.7	0.0	20.7	23.9
Rocky Mountain	47.5	222.0	0.0	222.0	269.5
West Coast	0.0	7.5	0.0	7.5	7.5
Shale Gas	35.1	770.6	56.0	826.6	861.7
Northeast	4.3	472.7	0.0	472.7	477.0
Gulf Coast	1.6	105.3	0.0	105.3	106.9
Midcontinent	7.3	62.6	0.0	62.6	69.9
Southwest	21.4	86.8	0.0	86.8	108.2
Rocky Mountain	0.4	43.2	14.6	57.8	58.3
West Coast	0.0	0.0	41.4	41.4	41.4
Coalbed Methane	20.8	68.1	49.3	117.4	138.2
Northeast	1.7	3.9	0.0	3.9	5.6
Gulf Coast	1.7	3.5	0.0	3.5	5.2
Midcontinent	0.9	4.3	31.8	36.1	37.0
Southwest	0.0	1.0	0.0	1.0	1.0
Rocky Mountain	16.5	55.4	7.2	62.7	79.1
West Coast	0.0	0.0	10.3	10.3	10.3
Other	78.7	236.1	197.8	433.9	512.5
Northeast	7.5	14.7	29.2	43.9	51.3
Gulf Coast	12.6	70.4	79.9	150.3	162.9
Midcontinent	21.8	20.6	21.4	42.0	63.7
Southwest	24.0	51.3	16.1	67.3	91.3
Rocky Mountain	10.5	63.9	28.0	91.9	102.4
West Coast	2.4	15.3	23.2	38.5	40.8
Lower 48 Offshore Non Associated	16.4	51.3	217.7	269.1	285.5
Gulf (currently available)	16.4	51.0	173.76	224.8	241.2
Eastern/Central Gulf (unavailable until 2022)	0.0	0.0	21.5	21.5	21.5
Pacific	0.0	0.3	10.1	10.4	10.4
Atlantic	0.0	0.0	12.4	12.4	12.4
Alaska (Onshore and Offshore)	7.7	24.8	257.5	282.3	290.0
Total U.S.	244.7	1520.3	778.3	2298.6	2543.3

[1] Includes 160.9 trillion cubic feet of associated-dissolved natural gas.
Note: Resources in other areas where drilling is officially prohibited are not included. The estimate of 32.9 trillion cubic feet of natural gas resources in the Northern Atlantic, Northern and Central Pacific, and within a 50-mile buffer off the Mid and Southern Atlantic OCS is also excluded from the technically recoverable volumes because leasing is not expected in these areas by 2035.
Source: Onshore, State Offshore, and Alaska - U.S. Geological Survey (USGS) with adjustments to tight gas, shale gas, and coalbed methane resources by Intek and Advanced Resources, International; Federal (Outer Continental Shelf) Offshore - Bureau of Ocean Energy Management (formerly the Minerals Management Service); Proved Reserves - U.S. Energy Information Administration. Table values reflect removal of intervening reserve additions between the date the the latest available assessment and January 1, 2009.

The OLOGSS evaluates the economics of future crude oil and natural gas exploration and development from the perspective of an operator making an investment decision. An important aspect of the economic calculation concerns the tax treatment. Tax provisions vary with the type of producer (major, large independent, or small independent). For the AEO2011, the economics of potential projects reflect the tax treatment provided by current laws for large independent producers. Relevant tax provisions are assumed unchanged over the life of the investment. Costs are assumed constant over the investment life but vary across region, fuel, and process type. Operating losses incurred in the initial investment period are carried forward and used against revenues generated by the project in later years.

Technology

Technology advances, including improved drilling and completion practices, as well as advanced production and processing operations are explicitly modeled to determine the direct impacts on supply, reserves, and various economic parameters. The success of the technology program is measured by estimating the probability that the technology development program will be successfully completed. It reflects the pace at which technology performance improves and the probability that the technology project will meet the program goals. There are four possible curves which represent the adoption of the technology: convex, concave, sigmoid/logistic or linear. The convex curve corresponds to rapid initial market penetration followed by slow market penetration. The concave curve corresponds to slow initial market penetration followed by rapid market penetration. The sigmoid/logistic curve represents a slow initial adoption rate followed by rapid increase in adoption and the slow adoption again as the market becomes saturated. The linear curve represents a constant rate of market penetration, and may be used when no other predictions can be made.

The market penetration curve is a function of the relative economic attractiveness of the technology instead of being a time-dependent function. A technology will not be implemented unless the benefits through increased production or cost reductions are greater than the cost to apply the technology. As a result, the market penetration curve provides a limiting value on commercialization instead of a specific penetration path. In addition to the curve, the implementation probability captures the fact that not all technologies that have been proved in the lab are able to be successfully implemented in the field. The specific technology levers and assumptions are shown in Table 9.3.

Table 9.3. Onshore lower 48 technology assumptions

	Ultimate Market Penetration	Market Penetration Curve	Probability of Successful R&D	Probability of Implementation	Drilling Success Rate	Exploration Sucess Rate	Injection Rate	Estimated Ultimate Recovery
Conventional Oil								
Infill Drilling	59%	linear	50%	44%	3%	3%	--	1%
Horizonal								
Continuity	60%	linear	51%	44%	3%	3%	25%	2%
Horizonal	61%	concave	49%	45%	3%	3%	2%	
Profile								1%
CO2 Flooding	61%	linear	51%	43%	3%	3%	38%	4%
Steam								
Flooding	60%	logistic	49%	44%	3%	3%	1%	9%
Polymer								
Flooding	61%	concave	50%	44%	3%	3%	12%	6%
Profile								
Modification	59%	concave	51%	42%	3%	3%	--	6%
Undiscovered	60%	concave	48%	44%	3%	3%	--	8%
Unconventional Oil	60%	concave	48%	44%	3%	3%	--	8%
Conventional Gas								
Developing	61%	linear	48%	46%	3%	3%	--	4%
Undiscovered	61%	linear	49%	45%	3%	3%	--	7%
Shale Gas								
Developing	61%	linear	48%	45%	3%	3%	--	8%
Undiscovered	61%	linear	48%	45%	3%	3%	--	7%
Coalbed Methane								
Developing	60%	linear	50%	44%	3%	3%	--	5%
Undiscovered	60%	linear	49%	43%	3%	3%	--	5%

Source: U.S. Energy Information Administration, Office of Energy Analysis.

CO2 enhanced oil recovery

For CO2 miscible flooding, the OLOGSS incorporates both industrial and natural sources of CO2. The industrial sources of CO2 are:

- Hydrogen plants
- Ammonia plants
- Ethanol plants
- Cement plants
- Refineries (hydrogen)
- Fossil fuel power plants
- Natural gas processing
- Coal/biomass to liquids

Technology and market constraints prevent the total volumes of CO2 (Table 9.4) from becoming immediately available. The development of the CO2 market is divided into 2 periods: 1) development phase and 2) market acceptance phase. During the development phase, the required capture equipment is developed, pipelines and compressors are constructed, and no CO2 is available. During the market acceptance phase, the capture technology is being widely implemented and volumes of CO2 first become available. The number of years in each development period is shown in Table 9.5. CO2 is available from planned CCS power plants funded by ARRA starting in 2016.

Table 9.4. Maximum volume of CO2 available

billion cubic feet

OGSM Region	Natural	Hydrogen	Ammonia	Ethanol	Cement	Refineries (hydrogen)	Power Plants	Natural Gas Processing
East Coast	0	3	0	52	94	17	12980	23
Gulf Coast	292	0	78	0	86	114	3930	114
Midcontinent	16	0	0	175	48	1	752	0
Southwest	657	0	0	68	74	0	0	0
Rocky Mountains	80	0	3	23	35	62	2907	12
West Coast	0	0	0	4	48	93	1134	40
Northern Great Plains	0	0	0	9	3	16	60	6

Source: U.S. Energy Information Administration. Office of Energy Analysis.
Note: Volumes for CDTL are received from the PMM.

Table 9.5. CO2 availability assumptions

Source Type	Development Phase (years)	Market Acceptance Phase (years)	Ultimate Market Acceptance
Natural	1	10	100%
Hydrogen	4	10	100%
Ammonia	2	10	100%
Ethanol	4	10	100%
Cement	7	10	100%
Refineries (hydrogen)	4	10	100%
Power Plants	12	10	100%
Natural Gas Processing	2	10	100%

Source: U.S. Energy Information Administration. Office of Energy Analysis.

The cost of CO2 from natural sources is a function of the oil price. For industrial sources of CO2, the cost to the producer includes the cost to capture, compress to pipeline pressure, and transport to the project site via pipeline within the region (Table 9.6). Inter-regional transportation costs add $0.40 per Mcf for every region crossed.

Table 9.6. Industrial CO2 capture & transportation costs by region

$/MCF

OGSM Region	Hydrogen	Ammonia	Ethanol	Cement	Refineries (hydrogen)	Power Plants	Natural Gas Processing	CBTL
East Coast	$2.44	$2.10	$2.23	$4.29	$2.44	$5.96	$1.92	$1.91
Gulf Coast	$1.94	$2.10	$2.23	$4.29	$1.94	$5.96	$1.92	$1.91
Midcontinent	$2.07	$2.10	$2.23	$4.29	$2.07	$5.96	$1.92	$1.91
Southwest	$2.02	$2.10	$2.23	$4.29	$2.02	$5.96	$1.92	$1.91
Rocky Mountains	$2.03	$2.10	$2.23	$4.29	$2.03	$5.96	$1.92	$1.91
West Coast	$2.01	$2.10	$2.23	$4.29	$2.01	$5.96	$1.92	$1.91
Northern Great Plains	$2.05	$2.10	$2.23	$4.29	$2.05	$5.96	$1.92	$1.91

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Lower 48 offshore

Most of the Lower 48 offshore oil and gas production comes from the deepwater of the Gulf of Mexico (GOM). Production from current producing fields and industry announced discoveries largely determine the short-term oil and natural gas production projection.

For currently producing fields, a 20-percent exponential decline is assumed for production except for natural gas production from fields in shallow water, which uses a 30-percent exponential decline. Fields that began production after 2008 are assumed to remain at their peak production level for 2 years before declining.

The assumed field size and year of initial production of the major announced deepwater discoveries that were not brought into production by 2007 are shown in Table 9.7. A field that is announced as an oil field is assumed to be 100 percent oil and a field that is announced as a gas field is assumed to be 100 percent gas. If a field is expected to produce both oil and gas, 70 percent is assumed to be oil and 30 percent is assumed to be gas.

Production is assumed to:

- ramp up to a peak level in 2 to 4 years depending on the size of the field,
- remain at the peak level until the ratio of cumulative production to initial resource reaches 20 percent for oil and 30 percent for natural gas,
- and then decline at an exponential rate of 20-30 percent.

The discovery of new fields (based on BOEM'S field size distribution) is assumed to follow historical patterns. Production from these fields is assumed to follow the same profile as the announced discoveries (as described in the previous paragraph).

Advances in technology for the various activities associated with crude oil and natural gas exploration, development, and production can have a profound impact on the costs associated with these activities. The specific technology levers and values for the offshore are presented in Table 9.8.

Oil shale liquids production

Projections for oil shale liquids production are based on underground mining and surface retorting technology and costs. The facility parameter values and cost estimates assumed in the projection are based on information reported for the Paraho Oil Shale Project, with the costs converted into 2004 dollars [6]. Oil shale rock mining costs, however, are based on current Rocky Mountain underground coal mining costs, which are representative oil shale rock mining costs. Oil shale facility investment and operating costs are assumed to decline by 1 percent per year. The construction of commercial oil shale production facilities is not permitted prior to 2017, based on the current status of petroleum company research, development and demonstration (RD&D) programs.

Although the petroleum company oil shale RD&D programs are focused primarily on the in-situ production of oil shale liquids, the underground mining and surface retorting process shares many similarities with the in-situ process. Moreover, because the in-situ process is still at the experimental stage, there are no publicly available estimates as to the in-situ process capital and operating costs required to produce a barrel of oil shale liquids at a commercial scale. Consequently, the underground mining and surface retorting costs, in conjunction with the 1 percent per year cost decline, are intended to be a surrogate for the in-situ process costs.

Table 9.7. Assumed size and initial production year of major announced deepwater discoveries

Field/Project Name	Block	Water Depth (feet)	Year of Discovery	Field Size Class	Field Size (MMBoe)	Start Year of Production
Ozona	GB515	3000	2008	12	89	2011
West Tonga	GC726	4674	2007	14	372	2011
Gladden	MC800	3116	2008	12	89	2011
Pony	GC468	3497	2006	14	372	2013
Knotty Head	GC512	3557	2005	14	372	2013
Puma	GC823	4129	2003	14	372	2013
Big Foot	WR029	5235	2005	13	182	2013
Cascade	WR206	8143	2002	14	372	2013
Chinook	WR469	8831	2003	14	372	2013
Pyrenees	GB293	2100	2009	12	89	2014
Kaskida	KC292	5860	2006	15	691	2014
Appaloosa	MC503	2805	2008	14	372	2014
Jack	WR759	6963	2004	14	372	2014
Samurai	GC432	3400	2009	12	89	2015
Wide Berth	GC490	3700	2009	12	89	2015
Manny	MC199	2478	2010	13	182	2015
Kodiak	MC771	4986	2008	13	182	2015
St. Malo	WR678	7036	2003	14	372	2015
Mission Deep	GC955	7300	2006	13	182	2016
Tiber	KC102	4132	2009	15	691	2016
Vito	MC984	4038	2009	13	182	2016
Stones	WR508	9556	2005	13	182	2016
Heidelberg	GC859	5000	2009	13	182	2017
Freedom	MC948	6095	2008	14	372	2017
Shenandoah	WR052	5750	2009	13	182	2017
Buckskin	KC872	6920	2009	13	182	2018
Julia	WR627	7087	2007	12	89	2018
Vicksburg	DC353	7457	2009	14	372	2019
Lucius	KC875	7168	2009	13	182	2019

Source: U.S. Energy Information Administration, Office of Energy Analysis

Table 9.8. Offshore exploration and production technology levels

Technology Level	Total Improvement (percent)	Number of Years
Exploration success rates	30	30
Delay to commence first exploration and between	15	30
Exploration & development drilling costs	30	30
Operating cost	30	30
Time to construct production facility	15	30
Production facility construction costs	30	30
Initial constant production rate	15	30
Decline rate	0	30

Source: U.S. Energy Information Administration, Office of Energy Analysis.

An individual oil shale project is assumed to produce 50,000 barrels per day of petroleum liquids and to process oil shale rock that produces, on average, 30 gallons of petroleum liquids per ton of rock. Oil shale production facilities are built when the net present value of their discounted cash flow exceeds zero. The discounted cash flow calculation uses a calculated discount rate that takes into consideration the financial risk associated with building oil shale facilities. Oil shale projects take 3 years to design, permit, license, and construct, with an additional 2 years required to reach full production capacity.

The oil shale market penetration algorithm assumes that higher project rates of return will result in a greater number of new projects initiating the construction process. So in any given year, higher oil prices will increase project rates of return, which in turn, will increase the number of new projects that begin the construction process.

The number of oil shale projects built in any year is determined by the number of projects already in operation and under construction relative to maximum number permitted by the oil shale market penetration algorithm. The maximum number of oil shale projects permitted in a particular year is determined by a 40-year linear penetration algorithm that caps the ultimate oil shale industry capacity at 2 million barrels per day of petroleum liquids production. The 2 million barrel per day ultimate capacity limit represents a feasible and sustainable production level based on the available water resources and air quality constraints that exist within the three State region of Colorado, Utah, and Wyoming, where the preponderance of high quality oil shale resources exist [7].

The maximum productive capacity calculated in any year is a function of the size of the project's positive discounted cash flow relative to the size of the project's capital investment. Multiple oil shale projects are initiated during a year, when the maximum capacity for that year exceeds the industry's operating and under-construction capacity by 100,000 barrels per day or more.

Oil shale liquids production is not resource constrained because approximately 400 billion barrels of petroleum liquids exist in oil shale rock with at least 30 gallons per ton of rock [8].

Because the in-situ process is still at the experimental stage, and because the underground mining and surface retorting process is unlikely to be environmentally acceptable on a large scale, the oil shale liquids production projections should be considered highly uncertain.

Alaska crude oil production

Projected Alaska oil production includes both existing producing fields and undiscovered fields that are expected to exist, based upon the region's geology. The existing fields category includes the expansion fields around the Prudhoe Bay and Alpine Fields for which companies have already announced development schedules. The initial production from these fields occurs in the first few years of the projection, with the projected oil production and the date of commencement based on the most current petroleum company announcements. Alaska crude oil production from the undiscovered fields is determined by the estimates of available resources in undeveloped areas and the net present value of the cash flow calculated for these undiscovered fields based on the expected capital and operating costs, and on the projected prices.

The discovery of new Alaskan oil fields is determined by the number of new wildcat exploration wells drilled each year and by the average wildcat success rate. The North Slope and South-Central wildcat well success rates are based on the success rates reported to the Alaska Oil and Gas Conservation Commission for the period of 1977 through 2008.

New wildcat exploration drilling rates are determined differently for the North Slope and South-Central Alaska. North Slope wildcat well drilling rates were found to be reasonably well correlated with prevailing West Texas Intermediate crude oil prices. Consequently, an ordinary least squares statistical regression was employed to develop an equation that specifies North Slope wildcat exploration well drilling rates as a function of prevailing West Texas Intermediate crude oil prices. In contrast, South-Central wildcat well drilling rates were found to be uncorrelated to crude oil prices or any other criterion. However, South-Central wildcat well drilling rates on average equaled just over 3 wells per year during the 1977 through 2008 period, so 3 South-Central wildcat exploration wells are assumed to be drilled every year in the future.

On the North Slope, the proportion of wildcat exploration wells drilled onshore relative to those drilled offshore is assumed to change over time. Initially, only a small proportion of all the North Slope wildcat exploration wells are drilled offshore. However, over time, the offshore proportion increases linearly, so that after 20 years, 50 percent of the North Slope wildcat wells are drilled onshore and 50 percent are drilled offshore. The 50/50 onshore/offshore wildcat well apportionment remains constant through the remainder of the forecast in recognition of the fact that offshore North Slope wells and fields are considerably more expensive to drill and develop, thereby providing an incentive to continue drilling onshore wildcat wells even though the expected onshore field size is considerably smaller than the oil fields expected to be discovered offshore.

The size of the new oil fields discovered by wildcat exploration drilling is based on the expected field sizes of the undiscovered Alaska oil resource base, as determined by the U.S. Geological Survey for the onshore and State offshore regions of Alaska, and by the Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) (formerly known as the U.S. Minerals Management Service) [9] for the Federal offshore regions of Alaska. It is assumed that the largest undiscovered oil fields will be found and developed first and in preference to the small and midsize undiscovered fields. As the exploration and discovery process proceeds and as the largest oil fields are discovered and developed, the discovery and development process proceeds to find and develop the next largest set of oil fields. This large to small discovery and development process is predicated on the fact that developing new infrastructure in Alaska, particularly on the North Slope, is an expensive undertaking and that the largest fields enjoy economies of scale, which make them more profitable and less risky to develop than the smaller fields.

Oil and gas exploration and production currently are not permitted in the Alaska National Wildlife Refuge. The projections for Alaska oil and gas production assume that this prohibition remains in effect throughout the projection period.

The greatest uncertainty associated with the Alaska oil projections is whether the heavy oil deposits located on the North Slope, which exceed 20 billion barrels of oil-in-place, will be producible in the foreseeable future at recovery rates exceeding a few percent.

Legislation and regulations

The Outer Continental Shelf Deep Water Royalty Act (Public Law 104-58) gave the Secretary of Interior the authority to suspend royalty requirements on new production from qualifying leases and required that royalty payments be waived automatically on new leases sold in the 5 years following its November 28, 1995 enactment. The volume of production on which no royalties were due for the 5 years was assumed to be 17.5 million barrels of oil equivalent (BOE) in water depths of 200 to 400 meters, 52.5 million BOE in water depths of 400 to 800 meters, and 87.5 million BOE in water depths greater than 800 meters. In any year during which the arithmetic average of the closing prices on the New York Mercantile Exchange for light sweet crude oil exceeded $28 per barrel or for natural gas exceeded $3.50 per million Btu, any production of crude oil or natural gas was subject to royalties at the lease stipulated royalty rate. Although automatic relief expired on November 28, 2000, the act provided the Minerals Management Service (MMS) the authority to include royalty suspensions as a feature of leases sold in the future. In September 2000, the MMS issued a set of proposed rules and regulations that provide a framework for continuing deep water royalty relief on a lease by lease basis. In the model it is assumed that relief will be granted roughly the same levels as provided during the first 5 years of the act.

Section 345 of the Energy Policy Act of 2005 provides royalty relief for oil and gas production in water depths greater than 400 meters in the Gulf of Mexico from any oil or gas lease sale occurring within 5 years after enactment. The minimum volume of production with suspended royalty payments are:

(1) 5,000,000 barrels of oil equivalent (BOE) for each lease in water depths of 400 to 800 meters;

(2) 9,000,000 BOE for each lease in water depths of 800 to 1,600 meters;

(3)12,000,000 BOE for each lease in water depths of 1,600 to 2,000 meters; and

(4) 16,000,000 BOE for each lease in water depths greater than 2,000 meters.

The water depth categories specified in Section 345 were adjusted to be consistent with the depth categories in the Offshore Oil and Gas Supply Submodule. The suspension volumes are 5,000,000 BOE for leases in water depths 400 to 800 meters; 9,000,000 BOE for leases in water depths of 800 to 1,600 meters; 12,000,000 BOE for leases in water depth of 1,600 to 2,400 meters; and 16,000,000 for leases in water depths greater than 2,400 meters. Examination of the resources available at 2,000 to 2,400 meters showed that the differences between the depths used in the model and those specified in the bill would not materially affect the model result.

The MMS published its final rule on the "Oil and Gas and Sulphur Operations in the Outer Continental Shelf-Relief or Reduction in Royalty Rates-Deep Gas Provisions" on January 26, 2004, effective March 1, 2004. The rule grants royalty relief for natural gas production from wells drilled to 15,000 feet or deeper on leases issued before January 1, 2001, in the shallow waters (less than 200 meters) of the Gulf of Mexico. Production of gas from the completed deep well must begin before 5 years after the effective date of the final rule. The minimum volume of production with suspended royalty payments is 15 billion cubic feet for wells drilled to at least 15,000 feet and 25 billion cubic feet for wells drilled to more than 18,000 feet. In addition, unsuccessful wells drilled to a depth of at least 18,000 feet would receive a royalty credit for 5 billion cubic feet of natural gas. The ruling also grants royalty suspension for volumes of not less than 35 billion cubic feet from ultra-deep wells on leases issued before January 1, 2001.

Section 354 of the Energy Policy Act of 2005 established a competitive program to provide grants for cost-shared projects to enhance oil and natural gas recovery through CO2 injection, while at the same time sequestering CO2 produced from the combustion of fossil fuels in power plants and large industrial processes.

From 1982 through 2008, Congress did not appropriate funds needed by the MMS to conduct leasing activities on portions of the Federal Outer Continental Shelf (OCS) and thus effectively prohibited leasing. Further, a separate Executive ban in effect since 1990 prohibited leasing through 2012 on the OCS, with the exception of the Western Gulf of Mexico and portions of the Central and Eastern Gulf of Mexico. When combined these actions prohibited drilling in most offshore regions, including areas along the Atlantic and Pacific coasts, the eastern Gulf of Mexico, and portions of the central Gulf of Mexico. In 2006, the Gulf of Mexico Energy Security Act imposed yet a third ban on drilling through 2022 on tracts in the Eastern Gulf of Mexico that are within 125 miles of Florida, east of a dividing line known as the Military Mission Line, and in the Central Gulf of Mexico within 100 miles of Florida.

On July 14, 2008, President Bush lifted the Executive ban and urged Congress to remove the Congressional ban. On September 30, 2008, Congress allowed the Congressional ban to expire. Although the ban through 2022 on areas in the Eastern and Central Gulf of Mexico remains in place, the lifting of the Executive and Congressional bans removed regulatory obstacles to development of the Atlantic and Pacific OCS.

Oil and gas supply alternative cases

Rapid and Slow Technology cases

Two alternative cases were created to assess the sensitivity of the projections to changes in the assumed rates of progress in oil and natural gas supply technologies. To create these cases a number of parameters representing technological penetration in the Reference case were adjusted to reflect a more rapid and a slower penetration rate. In the Reference case, the underlying assumption is that technology will continue to penetrate at historically observed rates. Since technologies are represented somewhat differently in different submodules of the Oil and Gas Supply Module, the approach for representing rapid and slow technology penetration varied as well. For instance, the effects of technological progress on crude oil and natural gas parameters in the Reference case, such as finding rates, drilling, lease equipment and operating costs, and success rates, were adjusted upward and downward by 50 percent, for the rapid and slow technology cases, respectively.

In the Canadian supply submodule, successful natural gas wells drilled for conventional and tight formations in the Western Canadian Sedimentary Basin (WCSB) are assumed to be 10 percent higher or lower in the rapid and slow technology cases, respectively, than they would be otherwise. For the other unconventional sources (coalbed and shale gas), the assumed undiscovered resource levels are progressively increased or ecreased (in the rapid and slow cases, respectively) over the forecast period to a level reaching 15 percent by 2030. In addition, the otherwise projected production levels for these unconventional sources are increased or decreased (in the rapid and slow cases, respectively) progressively over the forecast period to a level reaching 25 percent by 2030. Finally, the minimum supply prices deemed necessary to trigger the Alaska and MacKenzie Delta natural gas pipelines are progressively decreased or increased over the projection in the rapid and slow technology cases, respectively, downward or upward from 0.0 to 12.5 percent by 2030. All other parameters in the model were kept at their Reference case values, including technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about imports and exports of LNG and natural gas trade between the United States and Mexico. Production costs in the MacKenzie Delta vary across the projection period based on the estimated change in drilling costs in the lower 48 states, indirectly capturing the impact of different assumptions about technological improvement.

High and Low Shale Gas Resource cases

Estimates of technically recoverable shale gas resources are highly uncertain and change over time as new information is gained through drilling, production, and technology experimentation. Over the last decade, as more shale formations have gone into production, the estimate of technically recoverable shale gas resources has skyrocketed. However, these increases in technically recoverable shale gas resources embody many assumptions that might not prove to be true over the long-term and over the entire shale formation. For example, these shale gas resource estimates assume that gas production rates achieved in a limited portion of the formation are representative of the entire formation, even though neighboring shale gas well production rates can vary by as much as a factor of three. Moreover, the shale formation can vary significantly across the petroleum basin with respect to depth, thickness, porosity, carbon content, pore pressure, clay content, thermal maturity, and water content. Four cases were developed to examine the impact of the uncertainty inherent in these estimates.

High shale resource cases. The estimated unproved TRR (excluding inferred reserves) is increased 50 percent over the Reference case level. The TRR in these cases is 1,230 trillion cubic feet compared to 827 trillion cubic feet in the Reference case.

- High EUR case (hshleur). The estimated ultimately recovery (EUR) per shale gas well is assumed to be 50 percent higher than in the Reference case. The higher EUR per well could be the result, for example, 1) from better placement of the horizontal lateral within the formation, 2) better completion techniques that allow more of the pore space and absorbed gas to reach the well bore, and 3) the establishment that well recompletions are both productive and economic.

- High recoverability case (hshldrl). Fifty percent (50%) more natural gas can be recovered from the shale formation, even though the EUR per well stays constant. This outcome might result, for example, because a larger portion of the formation proves to be productive and economic than originally anticipated, and/or the drilling of more wells (and/or more horizontal laterals) closer to each other proves to be productive and economic. As a result, the overall recoverability of the gas-in-place in each shale gas play is increased by 50 percent.

Low Shale Resource cases. The Reference case TRR estimate (excluding inferred reserves) is reduced 50 percent. The TRR in these cases is 423 trillion cubic feet compared to 827 trillion cubic feet in the Reference case.

- Low EUR case (lshleur). The estimated ultimately recovery per shale gas well is assumed to be 50% lower than in the Reference case. The lower EUR per well could be the result, for example, of 1) earlier than expected abandonment of the well (e.g., low gas prices relative to high operating costs), 2) faster gas production decline rates than expected, and 3) considerably lower than expected EURs for wells in areas where the formation has not yet been tested.
- Low Recoverability case (lshldrl). Fifty percent less natural gas is recovered from each shale gas play, because, for example, a large portion of the formations are less productive and less economic than currently anticipated. The EUR per well is unchanged from the Reference case but the number of wells required to recover the resource is 50 percent lower as a result of a decreased estimate of the overall recoverability of the gas-in-place in each shale gas play.

The High and Low Offshore Crude Oil and Natural Gas Resource cases

The 2010 Macondo accident in the Gulf of Mexico has heightened the awareness of the risks and uncertainty associated with exploration and development of crude oil and natural gas resources in the offshore, particularly in the deep water. However, it is also clear that the resources available in the Gulf of Mexico and other offshore areas will remain an important component of U.S. supply through 2035. Lower 48 offshore production accounts for roughly 30 percent of total domestic crude oil production and 11 percent of total domestic natural gas production over the projection period.

Three sensitivity cases were created to evaluate the impact of key assumptions relating to the availability of lower 48 Outer Continental Shelf (OCS) crude oil and natural gas resources and the cost of exploration and development of these resources.

High OCS Resource case. An EIA Independent Expert Review (completed May 2010) indicates that higher and more productive resource levels than that currently estimated by the BOEMRE may be warranted given the era in which the estimates were made and the depth of data available. In three recent studies by API, NARUC, and DOE the technically recoverable resources in undeveloped areas of the OCS were increased 2 to 5 times the latest (2006) BOEMRE assessment. In this *AEO2011* sensitivity case, the crude oil and natural gas resource base in the Atlantic, Pacific, and Eastern Gulf of Mexico will be increased 3 times the Reference case assumption by tripling the number of fields in each field size class in these regions.

Reduced OCS Access case. This case will be developed around differing assumptions about leasing availability in the Pacific, Atlantic, and Eastern Gulf of Mexico OCS regions. The following table shows the specific leasing assumptions for this sensitivity case compared to the Reference case.

Leasing availability through 2035

	Reference	Reduced OCS Access
Eastern Gulf of Mexico	2022	None
North Atlantic	None	None
Mid and South Atlantic	2018	None
Northern & Central Pacific	None	None
Southern Pacific	2023	None

High OCS Costs case. The cost of exploration and development of offshore oil and gas resources is highly uncertain. For this case, costs will be increased 30 percent. This increase is not an estimate of how much costs will change as a result of any new regulatory and safety requirement but is simply an assumption used to highlight the impact of higher costs on the production of OCS crude oil and natural gas resources.

Notes and sources

[1] Technically recoverable resources are resources in accumulations producible using current recovery technology but without reference to economic profitability.

[2] Proved reserves are the estimated quantities that analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

[3] Inferred reserves are that part of expected ultimate recovery from known fields in excess of cumulative production plus current reserves.

[4] Undiscovered resources are located outside oil and gas fields in which the presence of resources has been confirmed by exploratory drilling; they include resources from undiscovered pools within confirmed fields when they occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic conditions.

[5] Donald L. Gautier and others, U.S. Department of Interior, U.S. Geological Survey, 1995 National Assessment of the United States Oil and Gas Resources, (Washington, D.C., 1995); U.S. Department of Interior, Minerals Management Service, Report to Congress: Comprehensive Inventory of U.S. OCS Oil and Natural Gas Resources, (February 2006); and 2003 estimates of conventionally recoverable hydrocarbon resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 2003.

[6] Source: Noyes Data Corporation, Oil Shale Technical Data Handbook, edited by Perry Nowacki, Park Ridge, New Jersey, 1981, pages 89-97. The Paraho Oil Shale Project design had a maximum production rate of 100,000 syncrude barrels per day, which is used in the OSSS as the standard oil shale facility size.

[7] U.S. Department of Energy, "Strategic Significance of America's Oil Shale Resource," Volume II - Oil Shale Resources Technology and Economics, Washington DC, May 2004, pages 7 and 34.

[8] Ibid. page 3.

[9] This agency was formerly known as the U.S. Minerals Management Service. In 2010, it was renamed the U.S. Bureau of Energy Ocean Management, Regulation and Enforcement.

Natural Gas Transmission and Distribution Module

The NEMS Natural Gas Transmission and Distribution Module (NGTDM) derives domestic natural gas production, wellhead and border prices, end-use prices, and flows of natural gas through the regional interstate network, for both a peak (December through March) and off peak period during each projection year. These are derived by solving for the market equilibrium across the three main components of the natural gas market: the supply component, the demand component, and the transmission and distribution network that links them. Natural gas flow patterns are a function of the pattern in the previous year, coupled with the relative prices of the supply options available to bring gas to market centers within each of the NGTDM regions (Figure 8). The major assumptions used within the NGTDM are grouped into five general categories. They relate to (1) structural components of the model, (2) capacity expansion and pricing of transmission and distribution services, (3) Arctic pipelines, and (4) imports and exports. A complete listing of NGTDM assumptions and in-depth methodology descriptions are presented in Model Documentation: Natural Gas Transmission and Distribution Model of the National Energy Modeling System, Model Documentation 2010, DOE/EIA-M062(2010) (Washington, DC, 2011).

Figure 8. Natural Gas Transmission and Distribution Module regions

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Key assumptions

Structural components

The primary and secondary region-to-region flows represented in the model are shown in Figure 8. Primary flows are determined, along with nonassociated gas production levels, as the model equilibrates supply and demand. Associated-dissolved gas production is determined in the Oil and Gas Supply Module (OGSM). Secondary flows are established before the equilibration process and are generally set exogenously. Liquefied natural gas (LNG) imports are also not directly part of the equilibration process, but are set at the beginning of each NEMS iteration in response to the price from the previous iteration. Flows and production levels are determined for each season, linked by seasonal storage. When required, annual quantities (e.g., consumption levels) are split into peak and off-peak values based on historical averages. When multiple regions are contained in a Census Division, regional end-use consumption levels are approximated using historical average shares. Pipeline and storage capacity are added as warranted by the relative volumes and prices. Regional pipeline fuel and lease and plant fuel consumption are established by applying an historically based factor to the flow of gas through a region and the production in a region, respectively. Prices within the network, including at the borders and the wellhead, are largely determined during the equilibration process. Delivered prices for each sector are set by adding an endogenously estimated markup (generally a distributor tariff) to the regional representative citygate price. Supply curves and electric generator gas consumption are provided by other NEMS modules for subregions of the NGTDM regions, reflective of how their internal regions overlap with the NGTDM regions.

Capacity expansion and pricing of transmission and distribution

For the first two projection years, announced pipeline and storage capacity expansions (that are deemed highly likely to occur) are used to establish limits on flows and seasonal storage in the model. Subsequently, pipeline and storage capacity is added when increases in consumption, coupled with an anticipated price increase, warrant such additions (i.e., flow is allowed to exceed current capacity if the demand still exists given an assumed increased tariff). Once it is determined that an expansion will occur, the associated capital costs are applied in the revenue requirement calculations in future years. Capital costs are assumed based on average costs of recent comparable expansions for compressors, looping, and new pipeline.

It is assumed that pipeline and local distribution companies build and subscribe to a portfolio of interstate pipeline and storage capacity to serve a region-specific colder-than-normal winter demand level, currently set at 30 percent above the daily average. Maximum pipeline capacity utilization in the peak period is set at 99 percent. In the off-peak period, the maximum is assumed to vary between 75 and 99 percent of the design capacity. The overall level and profile of consumption, as well as the availability and price of supplies, generally cause realized pipeline utilization levels to be lower than the maximum.

Pricing of services

While transportation tariffs for interstate pipeline services are initially based on a regulated cost-of-service calculation, an adjustment to the tariffs is applied which is dependent on the realized utilization rate, to reflect a market-based differential. Reservation and operation transportation rates for interstate pipeline services (both between NGTDM regions and within a region) are calculated assuming that the costs of new pipeline capacity will be rolled into the existing rate base.

Delivered prices by sector and season are derived by adding a markup to the average regional market price of natural gas in both peak and off-peak periods. (Prices are reported on an annual basis and represent quantity-weighted averages of the two seasons.) These markups include the cost of service provided by intraregional interstate pipelines, intrastate pipelines, and local distributors. The intrastate tariffs are accounted for endogenously through historical model benchmarking. Distributor tariffs represent the difference between the regional delivered and citygate price, independent of whether or not a customer class typically purchases gas through a local distributor.

The distribution tariffs are projected using econometrically estimated equations, primarily in response to changes in consumption levels. An assumed differential is used to divide the industrial price into one for non-core customers (refineries and industrial boiler users) and one for core customers who have fewer alternative fuel options.

The vehicle natural gas (VNG) sector is divided into fleet and non-fleet vehicles. In general, the distributor tariffs for natural gas to vehicles are set to EIA's Natural Gas Annual historical end-use prices minus citygate prices plus Federal and State VNG taxes (held constant in nominal dollars) plus an assumed dispensing cost. Dispensing costs are assumed to be $2.37 (2009 dollars per Mcf) as long as natural gas vehicles do not increase notably in market share. The assumed cost for adding a compressed natural gas retail facility is $401,000 (2009 dollars), after accounting for the tax value of depreciation, and is not considered economically viable at the low vehicle penetration rates projected.

Pipelines from arctic areas into Alberta

The outlook for natural gas production from the North Slope of Alaska is affected strongly by the unique circumstances regarding its transport to market. Unlike virtually all other identified deposits of natural gas in the United States, North Slope gas lacks a means of economic transport to major commercial markets. The lack of viable marketing potential at present has led to the use of Prudhoe Bay gas to maximize crude oil recovery in that field. The primary assumptions associated with estimating the cost of North Slope Alaskan gas in Alberta, as well as for MacKenzie Delta gas into Alberta, are shown in Table 10.1. A calculation is performed to estimate a regulated, levelized, tariff for each pipeline. Additional items are added to account for the wellhead price, treatment costs, pipeline fuel costs, and a risk premium to reflect the potential impact on the market price once the pipeline comes on line.

To assess the market value of Alaskan and Mackenzie Valley gas against the lower 48 market, a price differential of $0.73 (2009 dollars per Mcf) is assumed between the price in Alberta and the average lower 48 price. The resulting cost of Alaska gas, relative to the lower 48 wellhead price, is approximately $6.16 (2009 dollars per Mcf), with some variation across the projection due to changes in gross domestic product. Construction of an Alaska-to-Alberta pipeline is projected to commence if the assumed total costs for Alaska gas in the lower 48 States exceeds the average lower 48 gas price in each of the previous two years, on average over the previous five years (with greater weight applied to more recent years), and as expected to average over the next three years. An adjustment is made if prices were declining over the previous five years. Once the assumed four year construction period is complete, expansion can occur if the price exceeds the initial trigger price by $6.65 (2009 dollars per Mcf). Supplies to fill an expanded pipeline are assumed to require new gas wells. When the Alaska to Alberta pipeline is built in the model, additional pipeline capacity is added to bring the gas across the border into the United States. For accounting purposes, the model assumes that all of the Alaska gas will be consumed in the United States and that sufficient economical supplies are available at the North Slope to fill the pipeline over the depreciation period.

Natural gas production from the MacKenzie Delta is assumed to be sufficient to fill a pipeline over the projection period should one be built connecting the area to markets in the south. The basic methodology used to represent the decision to build a MacKenzie pipeline is similar to the process used for an Alaska-to-lower 48 pipeline, using the primary assumed parameters listed in Table 10.1. One exception is that wellhead costs are assumed to change across the projection period with estimated changes to drilling costs for the lower 48 States.

Supplemental natural gas

The projection for supplemental gas supply is identified for three separate categories: pipeline quality synthetic natural gas (SNG) from coal or coal-to-gas (CTG), SNG from liquids, and other supplemental supplies (propane-air, coke oven gas, refinery gas, biomass air, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas). The third category, other supplemental supplies, are held at a constant level of 9.8 billion cubic feet per year throughout the projection because this level is consistent with historical data and it is not believed to change significantly in the context of a Reference case. SNG from liquid hydrocarbons in Hawaii is assumed to continue over the projection at the average historical level of 2.6 billion cubic feet per year. SNG production from coal at the currently operating Great Plains Coal Gasification Plant is also assumed to continue through the projection period at an average historical level of 51.3 billion cubic feet per year. It is assumed that additional CTG facilities will be built if and when natural gas prices are high enough to make them economic. One CTG facility is assumed capable of processing 6,040 tons of bituminous coal per day, with a production capacity of 0.1 billion cubic feet per day of synthetic fuel and approximately 100 megawatts of capacity for electricity cogeneration sold to the grid. A CTG facility of this size is assumed to cost nearly $1 billion in initial capital investment (2009 dollars). CTG facilities are assumed to be built near existing coal mines. All NGTDM regions are considered potential locations for CTG facilities except for New England. Synthetic gas products from CTG facilities are assumed to be competitive when natural gas prices rise above the cost of CTG production (adjusted for credits from the sale of cogenerated electricity). It is assumed that CTG facilities will not be built before 2011.

Natural gas imports and exports

U.S. natural gas trade with Mexico is determined endogenously based on various assumptions about the natural gas market in Mexico. Natural gas consumption levels in Mexico are set exogenously based on projections from the *International Energy Outlook 2010* and are provided in Table 10.2, along with initially assumed Mexico production and LNG import levels targeted for markets in Mexico. Adjustments to production are made endogenously within the model to reflect a response to price fluctuations within the market. Domestic production is assumed to be supplemented by LNG from receiving terminals constructed on both the east and west coasts of Mexico. Maximum LNG import volumes targeted for markets in Mexico are set exogenously and will be realized if endogenously deternmined LNG imports into North America are sufficient. The difference between production plus LNG imports and consumption in any year is assumed to be either imported from, or exported to, United States.

Table 10.1. Primary assumptions for natural gas pipelines from Alaska and MacKenzie delta into Alberta, Canada

	Alaska to Alberta	MacKenzie Delta to Alberta
Initial flow into Alberta	3.8 billion cubic feet per day	1.1 billion cubic feet per day
Expansion potential	22 percent	58 percent
Initial capitalization	$35.6 billion (2009 dollars)	$10.6 billion (2009 dollars)
Cost of Debt (premium over 10 year treasury yield note)	0.75 percent	0.0 percent
Cost of equity (premium over 10 year treasury yield note)	6.5 percent	7.5 percent
Debt fraction	70 percent	60 percent
Depreciation period	20 years	20 years
Minimum wellhead price (including treatment and fuel costs)	$1.70 (2009 dollars per Mcf)	$3.12 (2009 dollars per Mcf)
Expected price reduction	$1.00 (2009 dollars per Mcf)	$0.06 (2009 dollars per Mcf)
Additional cost for expansion	$6.65 (2009 dollars per Mcf)*	$0.36 (2009 dollars per Mcf)
Construction period	4 years	4 years
Planning period	5 years	2 years
Earliest start year	2020	2015

*Includes added cost to explore for and produce natural gas beyond what has already been proven.
Source: U.S. Energy Information Administration, Office of Energy Analysis. Alaska pipeline cost data are based on Federal Energy Regulatory Commission, Docket PF09-11-001, "Open Season Plan Documents Submitted in Connection with Request for Commission Approval of Detailed Plan for Conducting an Open Season," submitted by TransCanada Alaska Company LLC on January 29, 2010, Volume III of III, Appendix C, Exhibit J – Recourse Rate Output, various pages. Note that the capital cost figure is the arithmetic average of the two $30.7 and $40.4 billion dollar capital cost estimates that include the mainline gas pipeline and the gas treatment plant, but which excludes the gas field line from Point Thomson to the gas treatment plant.
National Energy Board of Canada, "Mackenzie Gas Project – Hearing Order GH-1-2004, Supplemental Information – Project Update 2007," dated May 15, 2007;
National Energy Board of Canada, "Mackenzie Gas Project – Project Cost Estimate and Schedule Update," dated March 12, 2007;
Canada Revenue Agency, "T2 Corporation Income Tax Guide 2006," T4012(E) Rev. 07.
Indian and Northern Affairs Canada, "Oil and Gas in Canada's North," website address
http://www.ainc-inac.gc.ca/ps/ecd/env/nor_e.html.
National Energy Board of Canada, "Application for Approval of the Development Plan for Taglu Field - Project Description," submitted by Imperial Oil Resources Ltd., TDPA-P1, August 2004;
National Energy Board of Canada, "Application for Approval of the Development Plan for Niglintgak Field - Project Description," submitted by Shell Canada Ltd., NDPA-P1, August 2004; and
National Energy Board of Canada, "Application for Approval of the Development Plan for Parsons Lake Field - Project Description,"

Table 10.2. Exogenously specified Mexico natural gas consumption and supply
billion cubic feet per year

	Consumption	Initial Dry Production	Maximum LNG Imports
2010	2465	2028	201
2015	2500	1900	291
2020	3100	2100	331
2025	3600	2100	693
2030	4200	2100	1190
2035	5100	2100	1730

Source: Consumption - U.S. Energy Information Administration. *International Energy Outlook 2010*, DOE/EIA-0484(2010); Production - U.S. Energy Information Administration, Office of Petroleum, Gas, and Biofuels Analysis. LNG imports - U.S. Energy Information Administration, Office of Petroleum, Gas, and Biofuels Analysis and Sener, "Prospectiva del Mercado de Gas Natural."

Similarly to Mexico, Canada is modeled through a combination of exogenously and endogenously specified components. U.S. natural gas exports from the United States to Canada are set exogenously in NEMS starting at 724 billion cubic feet per year in 2010 and increasing to 1028 billion cubic feet by 2035. Canadian production and U.S. import flows from Canada are determined endogenously within the model. Canadian natural gas production in Eastern Canada and consumption are set exogenously in the model and are shown in Table 10.3. Production from conventional and tight formations in the Western Canadian Sedimentary Basin (WCSB) is calculated endogenously to the model using annual supply curves based on beginning-of-year proved reserves and an estimated production-to-reserve ratio. Reserve additions are set equal to the product of successful natural gas wells and a finding rate (both based on an econometric estimation). The initial coalbed methane, shale gas, and conventional WCSB economically recoverable resource base estimates assumed in the model are 8 trillion cubic feet (starting in 2008) , 153 trillion cubic feet (starting in 2012), and 95.8 trillion cubic feet (starting in 2004), respectively. [1] Potential production from tight formations was approximated by increasing the conventional resource level by 1.5 percent annually. Production from coalbed and shale sources is established based on an assumed production path which varies in response to the level of remaining resources and the solution price in the previous projection year.

Annual U.S. exports of liquefied natural gas (LNG) to Japan are assumed to continue at about 2008 levels of 39 billion cubic feet per year through March of 2013, when the export license expires, and cease thereafter. LNG exports from the lower 48 States are assumed to be zero throughout the forecast, as this option is currently not included in the model. LNG imports to the United States are determined endogenously within the model. For the most part, LNG imports are set endogenously in the model based on Atlantic/Pacific and peak/off-peak supply curves derived from model results generated by EIA's International Natural Gas Model (INGM). Prices from the previous model iteration are used to establish the total level of North American imports in the peak or off-peak period and in the Atlantic or Pacific. First, assumed LNG imports which are consumed in Mexico are subtracted (presuming the volumes are sufficient). Then, the remaining levels are allocated to the model regions based on last year's import levels, the available regasification capacity, and the relative prices. Regasification capacity is limited to facilities currently in existence and those already under construction, which is fully sufficient to accommodate import levels projected by the model.

Table 10.3. Exogenously specified Canada natural gas consumption and supply
billion cubic feet per year

Year	Consumption	Production Eastern Canada
2010	3,294	240
2015	3,200	530
2020	3,400	670
2025	3,700	820
2030	4,000	710
2035	4,300	620

Source: Consumption - U.S. Energy Information Administration. *International Energy Outlook 2010*, DOE/EIA-0484(2010); Production - Energy Information Administration, Office of Petroleum, Gas, and Biofuels Analysis. LNG imports - Energy Information Administration, Office of Petroleum, Gas, and Biofuels Analysis.

Legislation and regulations

The methodology for setting reservation fees for transportation services is initially based on a regulated rate calculation, but is ultimately consistent with FERC's alternative ratemaking and capacity release position in that it allows some flexibility in the rates pipelines ultimately charge. The methodology is market-based in that rates for transportation services will respond positively to increased demand for services while rates will decline should the demand for services decline.

A number of legislative actions have been taken to provide a favorable environment for the introduction of new liquefied natural gas (LNG) regasification facilities in the United States. In December 2002 under the Hackberry Decision, FERC terminated open access requirements for new onshore LNG terminals, placing them on an equal footing with offshore terminals regulated under provisions of the Maritime Security Act of 2002. The Maritime Security Act, signed into law in November 2002, also amended the Deepwater Port Act of 1974 to include offshore natural gas facilities, transferring jurisdiction for these facilities from the FERC to the Maritime Administration and the U.S. Coast Guard. The intent was to streamline the permitting process and relax regulator requirements. More recently an EPACT2005 provision clarified the role of the FERC as the final decision making body on issues concerning onshore LNG facilities. While none of these legislative/regulatory actions is explicitly represented in the modeling framework, projected LNG import volumes do not come close to reaching the U.S. regasification capacity existing today.

Section 116 of the Military Construction Appropriations and Emergency Hurricane Supplemental Appropriations Act, 2004 (H.R.4837) gives the Secretary of Energy the authority to issue Federal loan guarantees for an Alaska natural gas transportation project, including the Canadian portion, that would carry natural gas from northern Alaska, through the Canadian border south of 68 degrees north latitude, into Canada, and to the lower 48 States. This authority would expire 2 years after the final certificate of public convenience and necessity is issued. In aggregate the loan guarantee would not exceed: (1) 80 percent of total capital costs (including interest during construction); (2) $18 billion dollars (indexed for inflation at the time of enactment); or (3) a term of 30 years. The Act also promotes streamlined permitting and environmental review, an expedited court review process, and protection of rights-of-way for the pipeline. The assumed costs of borrowing money for the pipeline was reduced to reflect the decreased risk as a result of the loan guarantee.

Section 706 of the American Jobs Creation Act of 2004 (H.R.4520) provided a 7-year cost-of-investment recovery period for the Alaska natural gas pipeline, as opposed to the previously allowed 15-year recovery period, for tax purposes. The provision is effective for property placed in service after 2013 (or treated as such) and is assumed to have minimal impact on the decision to build the pipeline.

Section 707 of the American Jobs Creation Act extended the 15-percent tax credit previously applied to costs related to enhanced oil recovery to construction costs for a gas treatment plant that supplies natural gas to a 2 trillion Btu per day pipeline, lies in Northern Alaska, and produces carbon dioxide for injection into hydrocarbon-bearing geological formations. A gas treatment plan on the North Slope that feeds gas into an Alaska pipeline to Canada is expected to satisfy this requirement. The provision is effective for costs incurred after 2004. The impact of this tax credit is assumed to be factored into the cost estimates filed by the participating companies.

Section 312 of the Energy Policy Act of 2005 authorizes the Federal Energy Regulatory Commission (FERC) to allow natural gas storage facilities to charge market-based rates if it was believed that they would not exert market power. Storage rates are allowed to vary in the model from regulation-based rates, depending on market conditions.

Notes and sources

[1] Coalbed, shale gas, and tight sands based on assumptions used in EIA's International Natural Gas Model for the *International Energy Outlook 2010*.

Petroleum Market Module

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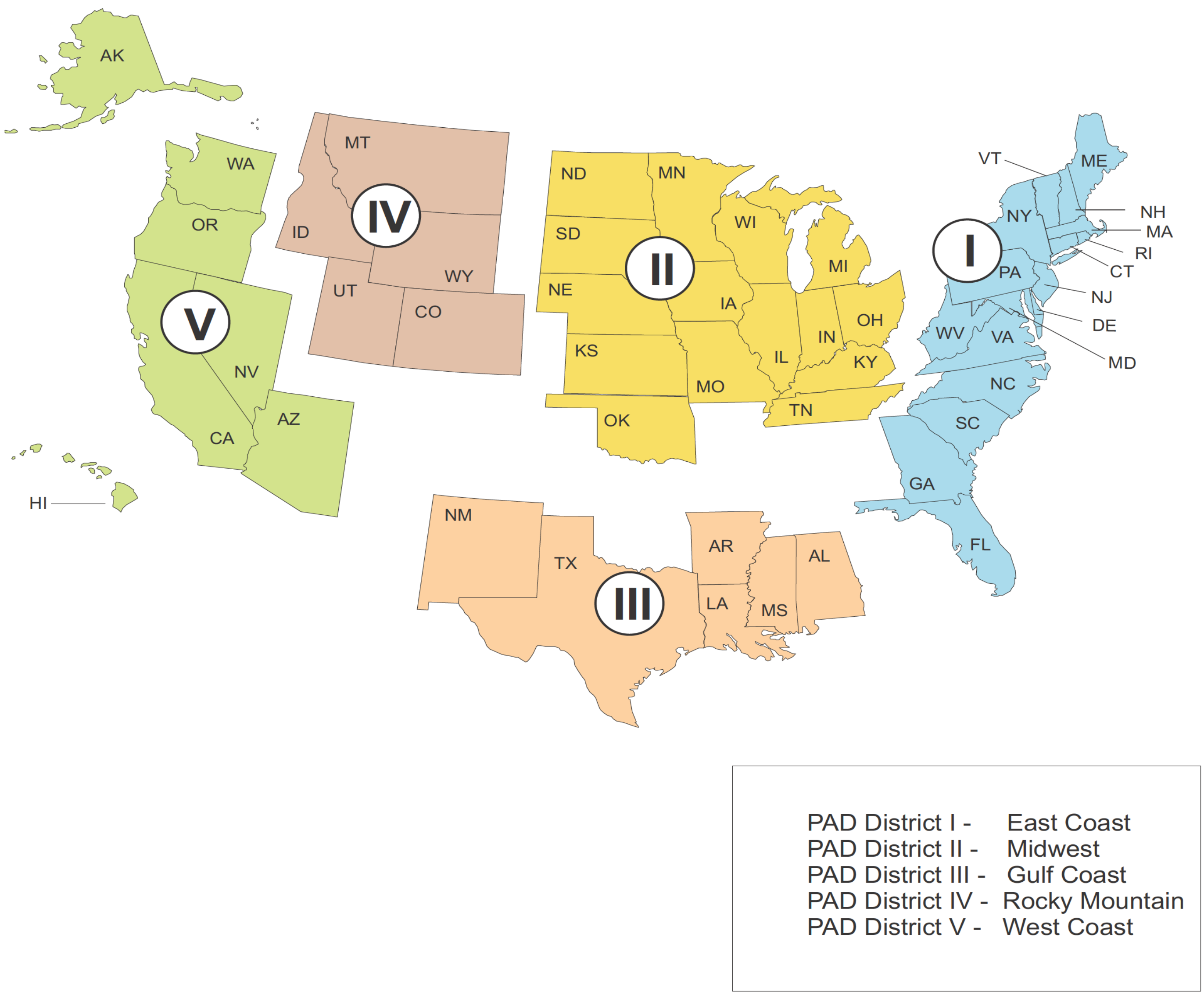
The NEMS Petroleum Market Module (PMM) projects petroleum product prices and sources of supply for meeting petroleum product demand. The sources of supply include crude oil (both domestic and imported), petroleum product imports, unfinished oil imports, other refinery inputs (including alcohols, ethers, bioesters, corn, biomass, and coal), natural gas plant liquids production, and refinery processing gain. In addition, the PMM projects capacity expansion and fuel consumption at domestic refineries.

The PMM contains a linear programming (LP) representation of U.S. refining activities in the five Petroleum Administration for Defense Districts (PADDs) (Figure 9), linked to a simplified world refining industry representation used to model U.S. crude and product imports. The U.S. segment of the LP model is created by aggregating individual U.S. refineries within a PADD into two types of representative refineries and linking all five PADDs and world refining regions via crude and product transit links. This representation provides the marginal costs of production for a number of conventional and new petroleum products. In order to interact with other NEMS modules with different regional representations, certain PMM inputs and outputs are converted from PADD regions to other regional structures and vice versa. The linear programming results are used to determine end-use product prices for each Census Division (shown in Figure 5) using the assumptions and methods described below.

Figure 9. Petroleum Administration for Defense Districts



Source: U.S. Energy Information Administration, Office of Energy Analysis.

Key assumptions

Product types and specifications

The PMM models refinery production of the products shown in Table 11.1.

The costs of producing different formulations of gasoline and diesel fuel that are required by State and Federal regulations are determined within the linear programming representation of refineries by incorporating the specifications and demands for these fuels. The PMM assumes that the specifications for these fuels will remain the same as currently specified, with a few exceptions: the sulfur content, which will be phased down to reflect EPA regulations for all gasoline and diesel fuels; and, benzene content, which will be reduced in gasoline beginning in 2011.

Table 11.1. Petroleum product categories

Product Category	Specific Products
Motor Gasoline	Conventional Unleaded, Reformulated
Jet Fuel	Kerosene-type
Distillates	Kerosene, Heating Oil, Low-Sulfur, Ultra-Low-Sulfur and CARB Diesel
Residual Fuels	Low Sulfur, High Sulfur
Liquefied Petroleum Gases	Propane, Liquefied Petroleum Gases Mixed
Petrochemical Feedstocks	Petrochemical Naptha, Petrochemical Gas Oil, Propylene, Aromatics
Others	Lubricating Products and Waxes, Asphalt/Road Oil, Still Gas Petroleum Coke, Special Naphthas, Aviation Gasoline

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Motor gasoline specifications and market shares

The PMM models the production and distribution of two different types of gasoline: conventional and reformulated (Phase 2). The following specifications are included in the PMM to differentiate between conventional and reformulated gasoline blends (Table 11.2): Reid vapor pressure (RVP), benzene content, aromatic content, sulfur content, olefins content, and the percent evaporated at 200 and 300 degrees Fahrenheit (E200 and E300). As of 2007, the sulfur content specification for gasoline has been reduced to 30 parts per million (ppm) [1].

Conventional gasoline must comply with anti-dumping requirements aimed at preventing the quality of conventional gasoline from eroding as the reformulated gasoline program is implemented. Conventional gasoline must meet the Complex Model II compliance standards which cannot exceed average 1990 levels of toxic and nitrogen oxide emissions [2].

Cellulosic biomass feedstock supplies and costs are taken from the NEMS Renewable Fuels Model. Initial capital costs for biomass cellulosic ethanol were obtained from a research project reviewing cost estimates from multiple sources [3]. Operating costs and credits for excess electricity generated at biomass ethanol plants were obtained from a survey of recent literature [4] and the USDA Agricultural Baseline Projections to 2019 [5].

Corn supply prices are estimated from the USDA baseline projections to 2019 [6]. The capital cost of a 50-million-gallon-per-year corn ethanol plant was assumed to be $84 million (2008 $). Operating costs of corn ethanol plants are obtained from USDA survey of ethanol plant costs [7]. Energy requirements are obtained from a study of carbon dioxide emissions associated with ethanol production [8].

Reformulated gasoline has been required in many areas in the United States since January 1995. In 1998, the EPA began certifying reformulated gasoline using the "Complex Model," which allows refiners to specify reformulated gasoline based on emissions reductions from their companies' respective 1990 baselines or the EPA's 1990 baseline. The PMM reflects "Phase 2" reformulated gasoline requirements which began in 2000. The PMM uses a set of specifications that meet the "Complex Model" requirements, but it does not attempt to determine the optimal specifications that meet the "Complex Model." (Table 11.3).

Table 11.2. Year round gasoline specifications by Petroleum Administration for Defense Districts (PADD), as of 2009

PADD	Reid Vapor Pressure (Max PSI)	Aromatics Volume Percent (Max)	Benzene Volume Percent (Max)	2007 Sulfur PPM (Max)	Olefin Volume Percent (Max)	Percent Evaporated at 200°	Percent Evaporated at 300°
Conventional							
PADD I	9.6	26.0	1.1	30.0	11.6	47.1	82.0
PADD II	10.2	26.1	1.1	30.0	11.6	47.1	81.9
PADD III	9.9	26.1	1.1	30.0	11.6	47.1	81.9
PADD IV	10.8	26.1	1.1	30.0	11.6	47.1	81.9
PADD V	9.2	26.7	1.1	30.0	11.7	45.7	81.4
Reformulated							
PADD I	8.5	20.7	0.6	30.0	11.9	50.2	84.6
PADD II	9.5	18.5	0.8	30.0	7.1	50.8	85.2
PADD III	8.6	19.8	0.6	30.0	11.2	51.6	83.9
PADD IV	8.6	19.8	0.6	30.0	11.2	51.6	83.9
PADD V							
Nonattainment	7.9	22.0	0.70	20.0	6.0	49.0	90.0
CARB (attainment)	7.9	22.0	0.70	20.0	6.0	49.0	90.0

Max = Maximum.
PADD = Petroleum Administration for Defense District.
PPM = parts per million by weight.
PSI = punds per square inch.
Benzene volume percent will change to 0.6 for all regions and type in 2011 to meet the MSAT2 ruling.
Source: U.S. Energy Information Administration, Office of Energy Analysis. Derived using U.S. EPA's Complex Model, and updated with U.S. EPA's gasoline projection survey "Fuel Trends Report: Gasoline 1995-2005", January 2008, EPA420-R-08-002. (http://www.epa.gov/otaq/regs/fuels/rfg/properf/rfgperf.htm).

Table 11.3. Market share for gasoline types by Census Division

Gasoline Type/Year	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
Conventional Gasoline	18	41	81	88	81	95	72	86	25
Reformulated Gasoline	82	59	19	12	19	5	28	14	75

Source: U.S. Energy Information Administration, Office of Energy Analysis. Derived from EIA-782C, "Monthly Report of Prime Supplier Sales of Petroleum Products Sold for Local Consumption," January-December 2009.
As of January 2007, Oxygenated Gasoline is included within Conventional Gasoline.

AEO2011 assumes MTBE was phased out by the end of 2007 as a result of decisions made by the petroleum industry. Ethanol is assumed to be used in areas where reformulated gasoline is required. Federal reformulated gasoline (RFG) is blended with up to 15 percent ethanol in vehicles 2001 and newer. Ethanol is also allowed to blend into conventional gasoline at up to 15 percent by volume, depending on its blending value and relative cost competitiveness with other gasoline blending components. However, current state regulation along with marketplace constraints limit the full penetration of E15 in the early part of the projection. EISA2007 defines a requirements schedule for having renewable fuels blended into transportation fuels by 2022.

Reid Vapor Pressure (RVP) limitations are effective during summer months, which are defined differently by consuming regions. In addition, different RVP specifications apply within each refining region, or PADD. The PMM assumes that these variations in RVP are captured in the annual average specifications, which are based on summertime RVP limits, wintertime estimates, and seasonal weights.

Within the PMM, total gasoline demand is disaggregated into demand for conventional and reformulated gasoline by applying assumptions about the annual market shares for each type. In AEO2011 the annual market shares for each region reflect actual 2009 market shares and are held constant throughout the projection. (See Table 11.3 for AEO2011 market share assumptions.)

Diesel fuel specifications and market shares

In order to account for ultra-low-sulfur diesel (ULSD) regulations related to Clean Air Act Amendment of 1990 (CAAA90), low-sulfur diesel is differentiated from other distillates. In NEMS, the Pacific Region (Census Division 9) is required to meet CARB standards. Both Federal and CARB standards currently limit sulfur to 15 ppm.

AEO2011 incorporates the ULSD regulation finalized in December 2000. ULSD is highway diesel that contains no more than 15 ppm sulfur at the pump. The ULSD regulation includes a phase-in period under the "80/20" rule, that requires the production of a minimum 80 percent ULSD for highway use between June 2006 and June 2010, and a 100 percent requirement for ULSD thereafter. As NEMS produces annual average results, only a portion of the production of highway diesel in 2006 is subject to the 80/20 rule and the 100 percent requirement does not cover all highway diesel until 2011.

NEMS models ULSD as containing 7.5 ppm sulfur at the refinery gate in 2006, phasing down to 7 ppm sulfur by 2011. This lower sulfur limit at the refinery reflects the general consensus that refiners will need to produce diesel with a sulfur content below 10 ppm to allow for contamination during the distribution process.

It is assumed that revamping (retrofitting) existing refinery units to produce ULSD will be undertaken by refineries representing two-thirds of highway diesel production and that the remaining refineries will build new units. The capital cost of revamping is assumed to be 50 percent of the cost of adding a new unit.

The amount of ULSD downgraded to a lower value product because of sulfur contamination in the distribution system is assumed to be 7.8 percent at the start of the program, declining to 2.2 percent at full implementation. The decline reflects the expectation that the distribution system will become more efficient at handling ULSD with experience.

A revenue loss is assumed to occur when a portion of ULSD that is put into the distribution system is contaminated and must be sold as a lower value product. The amount of the revenue loss is estimated offline based on earlier NEMS results and is included in the *AEO2011* ULSD price projections as a distribution cost. The revenue loss associated with the 7.8 percent downgrade assumption for 2009 is 0.7 cents per gallon. The revenue loss estimate declines to 0.2 cents per gallon after 2010 to reflect the assumed decline to 2.2 percent.

The capital and operating costs associated with ULSD distribution are based on assumptions used by the EPA in the Regulatory Impact Analysis (RIA) of the rule [9]. Capital costs of 0.7 cents per gallon are assumed for additional storage tanks needed to handle ULSD during the transition period. These capital expenditures are assumed to be fully amortized by 2011. Additional operating costs for distribution of highway diesel of 0.2 cents per gallon are assumed over the entire projection period. Another 0.2 cent cost per gallon is assumed for lubricity additives. Lubricity additives are needed to compensate for the reduction of aromatics and high-molecular-weight hydrocarbons stripped away by the severe hydrotreating used in the desulphurization process.

Demand for highway-grade diesel, both 500 ppm and ULSD combined, is assumed to be equivalent to the total transportation distillate demand. Historically, highway-grade diesel supplies have nearly matched total transportation distillate sales, although some highway-grade diesel has gone to nontransportation uses such as construction and agriculture.

The energy content of ULSD is assumed to decline from that of 500 ppm diesel by 0.5 percent because undercutting and severe desulphurization will result in a lighter stream composition than that for 500 ppm diesel.

AEO2011 incorporates the "nonroad, locomotive, and marine" (NRLM) diesel regulation finalized in May 2004. The PMM model has been revised to reflect the nonroad rule and re-calibrated for market shares of highway, NRLM diesel, and other distillate (mostly heating oil, but excluding jet fuel and kerosene). The NRLM diesel rule follows the highway diesel rule closely and represents an incremental tightening of the entire diesel pool. The demand for high sulfur distillate is expected to diminish over time, while the demand for ULSD (both highway and NRLM) is expected to increase over time.

The final NRLM rule is implemented in multiple steps and requires sulfur content for all NRLM diesel fuel produced by refiners to be reduced to 500 ppm starting mid-2007. It also establishes a new ULSD limit of 15 ppm for nonroad diesel by mid-2010. For locomotive and marine diesel, the rule establishes an ULSD limit of 15 ppm in mid-2012.

End-Use product prices

End-use petroleum product prices are based on marginal costs of production plus production-related fixed costs plus distribution costs and taxes. The marginal costs of production are determined within the LP and represent variable costs of production, including additional costs for meeting reformulated fuels provisions of the CAAA90. Environmental costs associated with controlling pollution at refineries are implicitly assumed in the annual update of the refinery investment costs for the processing units.

The costs of distributing and marketing petroleum products are represented by adding product-specific distribution costs to the marginal refinery production costs (product wholesale prices). The distribution costs are derived from a set of base distribution markups (Table 11.4).

State and Federal taxes are also added to transportation fuels to determine final end-use prices (Tables 11.5 and 11.6). Recent tax trend analysis indicates that State taxes increase at the rate of inflation, therefore, State taxes are held constant in real terms throughout the projection. This assumption is extended to local taxes which are assumed to average 2 cents per gallon [10]. Federal taxes are assumed to remain at current levels in accordance with the overall AEO2011 assumption of current laws and regulations. Federal taxes are not held constant but deflated as follows:

$\text{Federal Tax}_{\text{product, year}} = \text{Current Federal Tax}_{\text{product}} / \text{GDP Deflator}_{\text{year}}$

Crude oil quality

In the PMM, the quality of crude oil is characterized by average gravity and sulfur levels. Both domestic and imported crude oil are divided into five categories as defined by the ranges of gravity and sulfur shown in Table 11.7.

Table 11.4. Petroleum product end-use markups by sector and Census Division
2008 dollars per gallon

Sector/Product	Census Division: New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
Residential Sector									
Distillate Fuel Oil	0.44	0.49	0.24	0.21	0.37	0.23	0.36	0.28	0.35
Kerosene	1.34	0.73	0.29	0.31	0.22	0.33	0.33	0.75	0.85
Liquefied Petroleum Gases	1.29	1.33	0.81	0.57	1.28	1.12	1.00	0.95	1.12
Commercial Sector									
Distillate Fuel Oil	0.36	0.29	0.18	0.09	0.21	0.13	0.13	0.12	-0.17
Gasoline	0.15	0.15	0.14	0.13	0.13	0.15	0.14	0.18	0.19
Kerosene	1.35	0.56	0.27	0.33	0.22	0.29	0.29	0.99	1.06
Liquefied Petroleum Gases	0.55	0.80	0.62	0.62	0.79	0.70	0.74	0.77	0.64
Low-Sulfur Residual Fuel Oil	1.12	-0.04	0.76	0.71	0.12	0.15	0.06	0.00	0.14
Utility Sector									
Distillate Fuel Oil	0.30	0.24	0.10	-0.04	-0.01	-0.53	-0.38	0.21	-0.23
Residual Fuel Oil[1]	-0.36	-0.11	0.74	0.61	-0.07	-0.34	-0.57	0.75	0.60
Transportation Sector									
Distillate Fuel Oil	0.35	0.24	0.17	0.14	0.17	0.14	0.13	0.16	0.24
E85[2]	0.14	0.14	0.11	0.10	0.11	0.12	0.09	0.15	0.15
Gasoline	0.18	0.18	0.14	0.13	0.14	0.15	0.12	0.19	0.19
High-Sulfur Residual Fuel Oil[1]	0.44	-0.19	0.15	-0.56	0.10	-0.49	-0.54	0.00	0.73
Jet Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquefied Petroleum Gases	0.47	0.70	0.94	0.95	0.81	0.96	0.99	0.90	0.92
Industrial Sector									
Asphalt and Road Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distillate Fuel Oil	0.37	0.38	0.31	0.24	0.25	0.22	0.16	0.16	-0.21
Gasoline	0.18	0.17	0.14	0.13	0.14	0.16	0.14	0.19	0.19
Kerosene	-0.80	-0.04	0.04	0.00	-0.02	0.18	0.01	0.39	0.53
Liquefied Petroleum Gases	0.95	0.88	0.60	0.60	0.72	0.52	0.23	0.55	0.81
Low-Sulfur Residual Fuel Oil	0.89	-0.10	0.77	0.71	0.10	0.23	0.08	0.04	0.19

[1]Negative values indicate that average end-use sales prices were less than wholesale prices. This often occurs with residual fuel which is produced as a byproduct when crude oil is refined to make higher value products like gasoline and heating oil.
[2]74 percent ethanol and 26 percent gasoline.
Sources: Markups based on data from Energy Information Administration (EIA), Form EIA-782A, *Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report*; EIA, Form EIA-782B, *Resellers'/Retailers' Monthly Petroleum Report Product Sales Report*; EIA, Form FERC-423, *Monthly Report of Cost and Quality of Fuels for Electric Plants*; EIA, Form EIA-759 *Monthly Power Plant Report;* EIA, *State Energy Data Report 2008*, Consumption (June 2010); EIA, *State Energy Data 2008*: *Prices and Expenditures* (June 2010).

Table 11.5. State and local taxes on petroleum transportation fuels by Census Division, as of June 2010
2009 dollars per gallon

	Census Division								
Year/Product	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
Gasoline[1]	0.28	0.24	0.22	0.22	0.19	0.20	0.20	0.21	0.21
Diesel	0.30	0.28	0.23	0.23	0.22	0.19	0.19	0.23	0.21
Liquefied Petroleum Gases	0.13	0.13	0.18	0.20	0.19	0.18	0.14	0.15	0.06
E85[2]	0.22	0.19	0.18	0.17	0.14	0.15	0.15	0.16	0.17
Jet Fuel	0.08	0.05	0.00	0.03	0.05	0.06	0.02	0.04	0.03

[1]Tax also applies to gasoline consumed in the commercial and industrial sectors.
[2]74 percent ethanol and 26 percent gasoline.
Source: "Compilation of United States Fuel Taxes, Inspection, Fees and Environmental Taxes and Fees," Defense Energy Support Center, Editions 2010-10, June 5, 2010).

Table 11.6 Federal taxes, as of 2010
nominal dollars per gallon

Product	Tax
Gasoline	0.18
Diesel	0.24
Jet Fuel	0.04
Liquefied Petroleum Gases[3]	0.183
M85[1]	0.09
E85[2]	0.20

[1]85 percent methanol and 15 percent gasoline.
[2]74 percent ethanol and 26 percent gasoline.
[3]2010 data-based on EPACT05: excise tax is 4.3 cents/gal after 9-30-2011 and 18.3 cents/gal prior to that. A credit of 50 cents/gal was also applied between 10-1-06 and 9-30-09.
Sources: Omnibus Budget Reconciliation Act of 1993 (H.R. 2264); Tax Payer Relief Act of 1997 (PL 105-34), Clean Fuels Report (Washington, DC, April 1998) and Energy Policy Act of 2005 (PL 109-58). IRS Internal Revenue Bulletin 2006-43 available on the web at http://www.irs.gov/pub/irs-irbs/irb06-43.pdf

Table 11.7. Crude oil specifications

Crude Oil Categories	Sulfur (percent)	Gravity (degrees API)
Low Sulfur Light	0 - 0.5	25 - 60
Medium Sulfur Heavy	0.35-1.1	26 - 40
High Sulfur Light	> 1.1	>32
High Sulfur Heavy	> 1.1	24 - 33
High Sulfur Very Heavy	> 0.9	<23

Source: U.S. Energy Information Administration, Office of Energy Analysis. Derived from EI-810, "Monthly Refinery Report" data.

A "composite" crude oil with the appropriate yields and qualities is developed for each category by averaging the characteristics of specific crude oil streams in the category. While the domestic and foreign categories are the same, the composite crudes for each category may differ because different crude streams make up the composites. For domestic crude oil, estimates of total regional production are made first, then shared out to each of the five categories based on historical data. For imported crude oil, a separate supply curve is provided for each of the five categories. Each import supply curve is linked to a world oil supply market balance for that crude type, such that the quantity of crude oil imported depends on the economic competition with use by the rest of the world.

Capacity expansion

PMM allows for capacity expansion of all processing unit types including atmospheric distillation, vacuum distillation, hydrotreating, coking, fluid catalytic cracking, hydrocracking, and alkylation. Capacity expansion occurs by processing unit, starting from regional capacities established using historical data.

Expansion occurs in NEMS when the value received from the additional product sales exceeds the investment and operating costs of the new unit. The investment costs assume a financing ratio of 60 percent equity and 40 percent debt, with a hurdle rate and an after-tax return on investment of about 9 percent. Capacity expansion plans are determined every 3 years. For example, the PMM looks ahead in 2011 and determines the optimal capacities given the estimated demands and prices expected in the 2014 projection year. The PMM then allows any of that capacity to be built in each of the projection years 2012, 2013, and 2014. At the end of 2014 the cycle begins anew, looking ahead to 2017. ACU capacity under construction that is expected to begin operating in the future is added to existing capacities in their respective start year. Capacity expansion is also modeled for corn and cellulosic ethanol, coal-to-liquids, gas-to-liquids, and biomass-to-liquids production.

Alternative fuel technology characteristics

The PMM explicitly models a number of liquid fuels technologies that do not require petroleum feedstocks. These technologies produce both fuel grade products for blending with traditional petroleum products, as well as alternative feedstocks for the traditional petroleum refinery (Table 11.8).

Estimates of capital costs, operating cost, and process yield for these technologies are shown in Table 11.9. Costs are defined for 2010 and are escalated in the PMM using the GDP deflator. Owner's Capital Cost is defined as the anticipated cost for a fully continuous, commercial scale plant. However, some of the technologies have not yet been proven at a commercial scale. As a result, a technology optimism factor is applied to the owner's capital cost for the first plant of those technologies. For the next four plants, the capital cost decreases linearly such that the fifth plant is built at the owner's capital cost defined in the table. Following this phase, capital cost is decreased at a rate corresponding to the maturity of the components that make up the technology, reflecting the principle of learning by doing. This principle is implemented in the PMM in the same way as it is in the Electricity Market Module. Model parameters are shown in Table 11.10.

Table 11.8 Alternative fuel technology product type

Technology	Product Type
Biochemical	
Corn Ethanol	Fuel Grade
Barley Ethanol	Fuel Grade
Cellulosic Ethanol	Fuel Grade
Thermocatalytic	
Biomass Fisher-Tropsch	Fuel Grade/Refinery Feed
Pyrolysis Oil	Refinery Feed
Methyl Ester Biodiesel	Fuel Grade
Renewable Diesel	Fuel Grade
Biomass to Liquids (CBTL)	Fuel Grade/Refinery Feed
Natural Gas to Liquids (GTL)	Fuel Grade/Refinery Feed
Coal to Liquids (CTL)	Fuel Grade/Refinery Feed

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Table 11.9. Alternative fuel technology characteristics

United States Gulf Coast 2020 Basis (2009$)	Online Year	Nameplate Capacity[1]	Base Overnight Capital	Contingency Factors[2,3]		Total Overnight Capital[4]	Total Variable Cost[5]	Fixed O&M[6]	Thermal Efficiency[7]
		barrels/day	$/daily barrel	Project	Optimism	$/daily barrel	$/barrel	$/barrel	Energy Percent
Biochemical									
Corn Ethanol	-	6,523	$23,415	5%	0%	$24,586	$64.79	-	54%
Advanced Ethanol	2011	4,240	$25,757	5%	0%	$27,044	$73.69	-	49%
Cellulosic Ethanol (1st plant)	2011	3,700	$96,918	5%	25%	$127,204	$55.93	$12.03	28%
Cellulosic Ethanol (50th plant)	2011	3,700	$96,918	5%	25%	$73,449	$55.93	$12.03	28%
Thermocatalytic									
Coal/Biomass FT Liquids	2015	30,000	$132,586	10%	2.5%	$146,435	$12.74	$21.08	45%
Biomass FT Liquids (1st plant)	2012	3,143	$235,205	10%	25%	$316,798	$22.54	$37.92	47%
Biomass FT Liquids (50th plant)	2012	3,143	$235,205	10%	25%	$213,636	$22.54	$37.92	47%
Pyrolysis Oil (1st plant)	2014	687	$56,678	10%	25%	$76,339	$35.27	$23.82	52%
Pyrolysis Oil (50th plant)	2014	687	$56,678	10%	25%	$47,770	$35.27	$23.82	52%
Coal FT Liquids	2015	50,000	$132,707	10%	0%	$142,994	$11.24	$19.57	43%
Natural Gas FT Liquids[8]	2017	34,000	$66,372	10%	0%	$71,682	$47.06	$10.05	64%
Methyl Ester Biodiesel	-	1,305	$25,936	5%	0%	$27,233	$132.01	-	36%
Nonester Renewable Diesel	2010	2,000	$10,435	5%	2.5%	$11,123	$129.73	$1.75	38%

[1]For all processes except corn ethanol and FAME biodiesel, annual capacity refers to the capacity of one plant as defined in the Petrolem Market Module of NEMS. For corn ethanol and FAME biodiesel, annual capacity is the most common plant size as of 2008.
[2]Contingency is defined by the Amercian Association of Cost Engineers as a "specific provision for unforeseeable elements in costs within a defined project scope; particularly important where previous experience has shown that unforeseeable events which will increase costs are likely to occur."
[3]The technology optimism factor is applied to the first four units of an unproven design, reflecting a demonstrated tendency to underestimate costs for a first-of-a-kind unit.
[4]Total Overnight cost including contingency factors, excluding regional multipliers, learning effects, and interest charges.
[5]Variable Operating and Maintenance costs (O&M) include sales of electricity to the grid and coproduct value where applicable.
[6]For Corn Ethanol, Advanced Ethanol, and Biodiesel, fixed costs are included in Variable Operating Cost.
[7]A soybean oil mass yield of 20% is assumed in the crush facility in order to compute yield. Efficiency is defined as the heat content of the liquid products divided by the heat content of the feedstock.
[8]While these costs are for a Gulf Coast facility, the costs in other regions, particularly Alaska, are expected to be much higher.
Sources: The values shown in this table are developed by the Energy Information Administration, Office of Electricity, Coal, Nuclear, and Renewables Analysis, from analysis of reports and discussions with various sources from industry, government, and the Department of Energy Fuel Offices and National Laboratories. They are meant to represent the cost and performance of typical plants under normal oprating conditions for each technology. Key sources reviewed are listed in "Notes and Sources' at the end of the chapter.

Variable operating cost includes the cost of feedstock, utility requirements, coproduct credit, and other costs that depend on the capacity utilization and they represent the expected costs to operate a fully continuous, commercial scale plant for each technology. The breakdown is shown in Table 11.11.

Alternative fuels market dynamics

In the PMM, overnight capital costs are amortized and then added to variable and fixed costs in order to provide a cost of production [11]. As a result of this inclusion of capital cost in the cost of production, a given technology's production cost has the potential to become more or less attractive relative to other technologies as plants are built.

While cost of production defines a basis for comparison, market competition is often defined by the required feedstock. For example, technologies requiring greases and oils (biodiesel and renewable diesel) compete with each other for that feedstock, limiting the overall market share of each technology. As a consequence of this and the Renewable Fuels Standard, cellulosic ethanol and Biomass to Liquids (BTL) technologies, which include Fischer Tropsch and Pyrolysis, compete directly with each other. By contrast, technologies like Gas to Liquids and Coal to Liquids compete more directly with petroleum fuels, since their feedstocks are more similar to petroleum and their fuels are not required by the RFS.

Table 11.10 Alternative fuel technology learning parameters

	Plants Built	1st of a Kind	5th of a Kind		32nd of a Kind	
Cellulosic Ethanol	Mature	0%	33%	67%	0%	100%
	Decline Factor (b)	0.079	0.415	0.014	0.152	0.072
	Cumulative Capacity (a)	1.25	0.708	0.754	0.288	0.75
Biomass Fischer-Tropsch	Plant %	0%	0%	100%	0%	100%
	Decline Factor (b)	0.079	0.415%	0.014	0.152	0.072
	Cumulative Capacity (a)	1.250.000	1.128	1.126	0.000	1.126
Pyrolysis Oil	Plant %	0%	18%	82%	0%	100%
	Decline Factor (b)	0.079	0.418	0.014	0.152	0.072
	Cumulative Capacity (a)	1.28	0.386	0.923	0.155	0.923

Source: U.S. Energy Information Administration.

Variable operating cost includes the cost of feedstock, utility requirements, coproduct credit, and other costs that depend on the capacity utilization and they represent the expected costs to operate a fully continuous, commercial scale plant for each technology. The breakdown is shown in Table 11.11.

Table 11.11 Alternative fuel technology variable costs[1]

AEO2011 2020 Basis (Real 2009 $/barrel) Technology	Total	Feedstock Cost	Net Utility Cost[2]	Coproduct Credit	Other Variable[3]
Biochemical	-	-	-	-	-
Corn Ethanol	$64.79	$66.02	$10.44	$18.47	$6.69
Barley Ethanol	$73.69	$83.80	$3.52	$13/39	$6.79
Cellulosic Ethanol	$55.93	$30.05	$15.40	-	$41.28
Thermocatalytic	-	-	-	-	-
Coal/Biomass FT Liquids	$12.74	$17.84	$8.75	-	$3.65
Biomass FT Liquids	$22.54	$28.50	$10.21	-	$4.26
Pyrolysis Oil	$35.27	$26.11	$0.00	$4.62	$13.78
Coal FT Liquids	$11.24	$16.25	$8.75	-	$3.74
Natural Gas FT Liquids	$47.06	$45.84	$0.00	-	$1.22
Methyl Ester Biodiesel	$132.01	$124.87	$1.58	$0.74	$6.30
Nonester Renewable Diesel	$129.73	$127.27	$0.10	-	$2.36

[1]This table is based on the *AEO2011* Reference case projections for year 2020.
[2]Sales of electricity to the Grid from cogeneration are included in net utility costs.
[3]These costs are specific to each technology. Often cooling water, catalyst, and chemicals are applied here. For cellulosic ethanol, this includes enzyme costs and therefore is expected to decrease from $50.53/barrel in 2010 to $30.48/barrel in 2035.
Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear, and Renewables Analysis.

Biofuels supply

The PMM provides supply functions on an annual basis through 2035 for ethanol produced from both corn and cellulosic biomass to produce transportation fuel. It also assumes that small amounts of vegetable oil and animal fats are processed into biodiesel, a blend of methyl esters suitable for fueling diesel engines.

- Corn feedstock supplies and costs are provided exogenously to NEMS. Feedstock costs reflect credits for co-products (livestock feed, corn oil, etc.). Feedstock supplies and costs reflect the competition between corn and its co-products and alternative crops, such as soybeans and their co-products.
- Cellulosic (biomass) feedstock supply and costs are provided by the Renewable Fuels Module in NEMS.
- The Federal motor fuels excise tax credit of 45 cents per gallon of ethanol (4.5 cents per gallon credit to gasohol at a 10-percent volumetric blending portion) is applied within the model. The tax credit is held constant in nominal terms, decreasing with inflation throughout the projection in constant dollar terms. It is assumed that the credit expires after 2011.

To model the Renewable Fuels Standard in EISA2007, several assumptions were required. In addition to using the text of the legislation, it was also assumed that rules promulgated under the RFS in EPACT05 would govern the administration of the EISA2007 RFS through June 2010. After that point, the administration is governed by the most recent RFS rulemaking.

- The penetration of cellulosic ethanol into the market is limited before 2012 to the likely projects currently expected to produce approximately 4 million gallons per year.
- Methyl ester biodiesel production contributes 1.5 credits towards the advanced mandate.
- Renewable diesel fuel, including that from Pyrolysis oil, and Fischer-Tropsch diesel contribute 1.7 credits toward the cellulosic mandate.
- Renewable gasoline, including that from Pyrolysis oil, and Fischer-Tropsch naphtha contribute 1.54 credits toward the cellulosic mandate.
- Imported Brazilian sugarcane ethanol counts towards the advanced renewable mandate. Supply curves for sugarcane ethanol imports allow for substantial penetration by 2022 (1.5 billion gallons) into the U.S. advanced fuel supply pool, after which sugarcane ethanol remains competitive due to its relatively low production cost, availability, and the assumed expiration of the 54 cents/gallon import tariff by Jan. 1, 2012. Ample sugarcane ethanol supply for export from Brazil is supported by outside forecasts [12]. In addition, cellulosic ethanol would be available for export to the U.S. (largely from bagasse feedstock) but this supply is limited in part due to competition with the growing use of sugarcane residue for electricity generation in Brazil.
- Separate biofuel waivers can be activated by the EPA for each of the four RFS fuel categories. In years beyond 2022, the RFS mandate levels continue to increase toward 36 billion gallons. When this value is reached, the volumes continue to rise with US demand for transportation fuel.
- It is assumed that biodiesel and BTL diesel may be consumed in diesel engines without significant infrastructure modification (either vehicles or delivery infrastructure).
- Ethanol is assumed to be consumed as E10, E15 or E85, with no intermediate blends. The cost of placing E85 pumps at the most economic stations is spread over diesel and gasoline.
- To accommodate the ethanol requirements in particular, transportation modes are expanded or upgraded for E10, E15 and E85, and it is assumed that most ethanol originates from the Midwest, with nominal transportation costs ranging from a low of 1.7 cents per gallon for expanded distribution in the Midwest, to as high as 2.6 cents per gallon for the Southeast and West Coast.
- For E85 dispensing stations, it is assumed the average cost of a retrofit and new station is about $45,000 per station, which translates into an incremental cost per gallon ranging from 26 cents in 2013 to 3 cents by 2020, depending on the average sales per dispenser.
- The total projected incremental nominal infrastructure cost (transportation, distribution, dispensing) for E85 varies from 27 cents per gallon of E85 in 2013 to 5 cents per gallon in 2020.

Interregional transportation is assumed to be by rail, ship, barge, and truck, and the associated costs are included in PMM. A subsidy is offered by the Department of Agriculture's Commodity Credit Corporation for the production of biodiesel. In addition, the American Jobs Creation Act of 2004 provides an additional tax credit of $1 per gallon of soybean oil for biodiesel and 50 cents per gallon for yellow grease biodiesel until 2006, and EPACT05 extended the credit again to 2008. The Emergency Stabilization Act of 2008 extended it again to 2009 and increased the yellow grease credit to $1 per gallon

Non-biofuel alternative supply

Gas-to-liquids (GTL) facilities convert natural gas into distillates, and are assumed to be built if the prices for lower sulfur distillates reach a high enough level to make it economic. In the PMM, gas-to-liquids facilities are assumed to be built only on the North Slope of Alaska, where the distillate product is transported on the Trans-Alaskan Pipeline System (TAPS) to Valdez and shipped to markets in the lower 48 States. The earliest start date for a GTL facility is set at 2017. Since the Alaska Natural Gas Transportation System (ANGTS) is not economic in the AEO2011, the Alaska GTL plant has access to associated gas resources currently used to increase oil recovery. The transportation cost to ship the GTL product from the North Slope to Valdez along the TAPS is assumed to be the price set to move oil (i.e. the TAPS revenue recovery rate). This rate is a function of allowable costs, profit, and flow, and can change over the projection.

It is also assumed that coal-to-liquids (CTL) facilities will be built when low-sulfur distillate prices are high enough to make them economic. Additionally, a process which allows co-firing of coal with biomass (CBTL) is explicitly modeled for producers who wish to receive RFS credit for a portion of their product. A 50,000 barrel per day CTL facility is assumed to cost about $7 billion in initial capital investment (2009 dollars) while a 30,000 barrel per day CBTL facility is expected to cost about $4.4 billion. These facilities could be built near existing refineries. For the East Coast, potential CTL facilities could be built near the Delaware River basin; for the Central region, near the Illinois River basin or near Billings, Montana; and for the West Coast, in the vicinity of Puget Sound in Washington State. It is further assumed that CTL facilities can only be built after 2014.

Gasification of petroleum coke (petcoke) and heavy oil (asphalt, vacuum resid, etc.) is represented in AEO2011. The PMM assumes petcoke to be the primary feedstock for gasification, which in turn could be converted to either combined heat and power (CHP) or hydrogen production based on refinery economics. A typical gasification facility is assumed to have a capacity of 2,000 tons-per-day (TPD), which includes the main gasifier and other integrated units in the refinery such as air separation unit (ASU), syngas clean-up, sulfur recovery unit (SRU), and two downstream process options - CHP or hydrogen production. Currently, there is more than 5,000 TPD of gasification capacity in the U.S. that produces CHP and hydrogen.

Combined heat and power (CHP)

Electricity consumption in the refinery is a function of the throughput of each unit. Sources of electricity consist of refinery power generation, utility purchases, refinery CHP, and merchant CHP. Power generators and CHP plants are modeled in the PMM linear program as separate units which are allowed to compete along with purchased electricity. Both the refinery and merchant CHP units provide estimates of capacity, fuel consumption, and electricity sales to the grid based on historical parameters.

Refinery sales to the grid are estimated using the following percentages which are based on 2005 data:

Region	Percent Sold To Grid
PADD I	67.0
PADD II	0.9
PADD III	2.2
PADD IV	0.9
PADD V	45.4

Source: U.S. Energy Information Administration. Derived using EIA-860B, "Annual Electric Generators Report-Nonutility".

Merchant CHP plants are defined as non-refiner owned facilities located near refineries to provide energy to the open market and to the neighboring refinery. These sales occur at a price equal to the average wholesale price of electricity in each PMM region, which are obtained from the Electricity Market Model.

Short-term methodology

Petroleum balance and price information for 2009 and 2010 are projected at the U.S. level in the Short-Term Energy Outlook, (STEO). The PMM adopts the STEO results for 2009 and 2010, using regional estimates derived from the national STEO projections.

Legislation and regulation

The Tax Payer Relief Act of 1997 reduced excise taxes on liquefied petroleum gases and methanol produced from natural gas. The reductions set taxes on these products equal to the Federal gasoline tax on a Btu basis.

Title II of CAAA90 established regulations for oxygenated and reformulated gasoline and reduced-sulfur (500 ppm) on-highway diesel fuel. These are explicitly modeled in the PMM. Reformulated gasoline represented in the PMM meets the requirements of phase 2 of the Complex Model, except in the Pacific region where it meets CARB 3 specifications.

AEO2011 reflects "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements finalized by EPA in February 2000. This regulation requires that the average annual sulfur content of all gasoline used in the United States be phased-down to 30 ppm between the years 2004 and 2007. The 30 ppm annual average standard is not fully realized in conventional gasoline until 2008 due to allowances for small refineries.

AEO2011 reflects Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements finalized by the EPA in December 2000. Between June 2006 and June 2010, this regulation requires that 80 percent of highway diesel supplies contain no more than 15 ppm sulfur while the remaining 20 percent of highway diesel supplies contain no more than 500 ppm sulfur. After June 2010, all highway diesel is required to contain no more than 15 ppm sulfur at the pump.

AEO2011 reflects nonroad locomotive and marine (NRLM) diesel requirements finalized by the EPA in May 2004. Between June 2007 and June 2010, this regulation requires that nonroad diesel supplies contain no more than 15 ppm sulfur. For locomotive and marine diesel, the action establishes a NRLM limit of 15 ppm in mid-2012.

AEO2011 incorporates the American Jobs Creation Act of 2004 to extend the Federal tax credit of 51 cents per gallon of ethanol blended into gasoline through 2010.

AEO2011 represents major provisions in the Energy Policy Act of 2005 (EPACT05) concerning the petroleum industry, including: 1) removal of oxygenate requirement in RFG; and 2) extension of tax credit of $1 per gallon for soybean oil biodiesel and $0.50 per gallon for yellow grease biodiesel through 2008.

The Emergency Stabilization Act of 2008 extended the soybean oil for biodiesel tax credit again to 2009 and increased the yellow grease credit to $1 per gallon.

AEO2011 includes provisions outlined in the Energy Independence and Security Act of 2007 (EISA2007) concerning the petroleum industry, including a Renewable Fuels Standard (RFS) increasing total U.S. consumption of renewable fuels. Although the statute calls for higher levels, due to uncertainty about whether the new RFS schedule can be achieved and the stated mechanisms for reducing the cellulosic biofuel schedule, the final schedules in PMM were assumed to be: 1) 30.9 billion gallons in 2023 for all fuels; 2) 15.9 billion gallons in 2023 for advanced biofuels; 3) 10.9 billion gallons in 2023 for cellulosic biofuel; 4) 1 billion gallons of biodiesel by 2023 [13].

AEO2011 includes the EPA Mobil Source Air Toxics (MSAT 2) rule which includes the requirement that all gasoline products (including reformulated and conventional gasoline) produced at a refinery during a calendar year will need to contain no more than 0.61 percent benzene by volume. This does not include gasoline produced or sold in California which is already covered by the current California Phase 3 Reformulated Gasoline Program.

AEO2011 includes California's Low Carbon Fuel Standard which aims to reduce the Carbon Intensity (CI) of gasoline and diesel fuels in that State by 10% respectively from 2012 through 2020 . Due to limitations in the PMM's regionality, this regulation is modeled by assuming all of the Pacific/Census Region 9 (which also includes Washington, Oregon, Alaska, and Hawaii) is under the same LCFS, as California makes up the vast majority of motor gasoline and diesel fuel consumption in this region. The LCFS places two separate mandates on gasoline and diesel fuels sold in the state respectively, which are reduced through the use of an assortment of approved low carbon fuel pathways as regulated by the California Air Resources Board (ARB). *AEO2011* uses the most up to date Carbon Intensity and Life Cycle Analysis data provided by ARB at the time of release.

AEO2011 includes mandates passed in 2010 by Connecticut, Maine, New York, and New Jersey that aim to lower the sulfur content of all heating oil to ultra-low sulfur diesel over different time schedules, as well as transition to a 2% biodiesel content by mid 2011 in the case of Maine and Connecticut.

Due to the uncertainty surrounding compliance options, *AEO2010* did not include any explicit modeling treatment of the International Maritime Organization's "MARPOL Annex 6" rule covering cleaner marine fuels and ocean ship engine emissions.

Notes and sources

[1] U.S. Environmental Protection Agency, "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements, February 2000 (Washington, DC).

[2] Federal Register, U.S. Environmental Protection Agency, 40 CFR Part 80, Regulation of Fuels and Fuel Additives: Standards for Reformulated and Conventional Gasoline, Rules and Regulations, p. 7800, (Washington, DC, February 1994).

[3] Marano, John, "Alternative Fuels Technology Profile: Cellulosic Ethanol", March 2008. [4] Ibid.

[5] U.S. Department of Agriculture, "USDA Agricultural Baseline Projections to 2019," February 2009, http://www.ers.usda.gov/publications/oce091.

[6] Ibid

[7] Shapouri Hosein; Gallagher, Paul; and Graboski, Mike. USDA's 1998 Ethanol Cost-of-Production Survey. January 2002.

[8] Marland, G. and A.F. Turhollow. 1991. "CO2 Emissions from the Production and Combusion of Fuel Ethanol from Corn." Energy, 16(11/12):1307-1316.

[9] U.S. Environmental Protection Agency, Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements, EPA420-R-00-026 (Washington, DC, December

2000).

[10] American Petroleum Institute, How Much We Pay for Gasoline: 1996 Annual Review, May 1997.

[11] Economic lifetime is 15 years for cellulosic ethanol, biomass Fischer-Tropsch, and Pyrolysis Oil. It is 20 years for all others. Required rate of return is calculated using a 60:40 debt to equity ratio and the capital asset pricing model for the cost of equity.

[12] http://www.agrievolution.com/atti/brasile_02.ppt.

[13] The 2023 RFS levels used in the PMM reinstates the temporary reductions (1.1 billion gallons) that were needed in 2022 for the all fuels, advanced biofuels, and cellulosic biofuel categories

Coal Market Module

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The NEMS Coal Market Module (CMM) provides projections of U.S. coal production, consumption, exports, imports, distribution, and prices. The CMM comprises three functional areas: coal production, coal distribution, and coal exports. A detailed description of the CMM is provided in the EIA publication, Coal Market Module of the National Energy Modeling System 2011, DOE/EIA-M060(2011) (Washington, DC, 2011).

Key assumptions

Coal production

The coal production submodule of the CMM generates a different set of supply curves for the CMM for each year of the projection. Forty-one separate supply curves are developed for each of 14 supply regions, nine coal types (unique combinations of thermal grade and sulfur content), and two mine types (underground and surface). Supply curves are constructed using an econometric formulation that relates the minemouth prices of coal for the supply regions and coal types to a set of independent variables. The independent variables include: capacity utilization of mines, mining capacity, labor productivity, the user cost of capital of mining equipment, the cost of factor inputs (labor and fuel), and other mine supply costs.

The key assumptions underlying the coal production modeling are:

- As capacity utilization increases, higher minemouth prices for a given supply curve are projected. The opportunity to add capacity is allowed within the modeling framework if capacity utilization rises to a pre-determined level, typically in the 80 percent range. Likewise, if capacity utilization falls, mining capacity may be retired. The amount of capacity that can be added or retired in a given year depends on the level of capacity utilization, the supply region, and the mining process (underground or surface). The volume of capacity expansion permitted in a projection year is based upon historical patterns of capacity additions.
- Between 1980 and 2000, U.S. coal mining productivity increased at an average rate of 6.6 percent per year from 1.93 to 6.99 tons per miner per hour. The major factors underlying these gains were interfuel price competition, structural change in the industry, and technological improvements in coal mining [1]. Since 2000, however, growth in overall U.S. coal mining productivity has been negative, declining at a rate of 2.4 percent per year to 5.61 tons per miner hour in 2009. By region, productivity in most of the coal producing basins represented in the CMM has declined some during the past nine years. In the Central Appalachian coal basin, which has been mined extensively, productivity declined by a significant 42 percent between 2000 and 2009, corresponding to an average decline of 5.9 percent per year.
- Over the projection period, labor productivity is expected to decline in a number of coal supply regions, reflecting the trend of the previous nine years. Higher stripping ratios and the added labor needed to maintain more extensive underground mines offset productivity gains achieved from improved equipment, automation, and technology. Productivity in some areas of the East is projected to decline as operations move from mature coalfields to marginal reserve areas. Regulatory restrictions on surface mines and fragmentation of underground reserves limit the benefits that can be achieved by Appalachian producers from economies of scale.
- In the CMM, different rates of productivity improvement are assumed for each of the 41 coal supply curves used to represent U.S. coal supply. These estimates are based on recent historical data and expectations regarding the penetration and impact of new coal mining technologies [2]. Data on labor productivity are provided on a quarterly and annual basis by individual coal mines and preparation plants on the U.S. Mine Safety and Health Administration's Form 7000-2, "Quarterly Mine Employment and Coal Production Report" and the Energy Information Administration's Form EIA-7A, "Coal Production Report". In the Reference case, overall U.S. coal mining labor productivity declines at rate 0.3 percent a year between 2009 and 2035. Reference case projections of coal mining productivity by region are provided in Table 12.1.
- With the exception of the *AEO2011* Low and High Coal Cost cases, both the wage rate for U.S. coal miners and mine equipment costs are assumed to remain constant in 2009 dollars (i.e., increase at the general rate of inflation) over the projection period. This assumption primarily reflects the historic trends in these cost variables.

Coal distribution

The coal distribution submodule of the CMM determines the least-cost (minemouth price plus transportation cost) supplies of coal by supply region for a given set of coal demands in each demand sector using a linear programming algorithm. Production and distribution are computed for 14 supply (Figure 10) and 16 demand regions (Figure 11) for 49 demand subsectors.

The projected levels of coal-to-liquids, industrial steam, coking, and residential/commercial lcoal demand are provided by the petroleum market, industrial, commercial, and residential demand modules, respectively; electricity coal demands are projected by the EMM; coal imports and coal exports are projected by the CMM based on non-U.S. supply availability, endogenously determined U.S. import demand, and exogenously determined world coal demand (non-U.S.)

Table 12.1. Coal mining productivity by region
short tons per miner hour

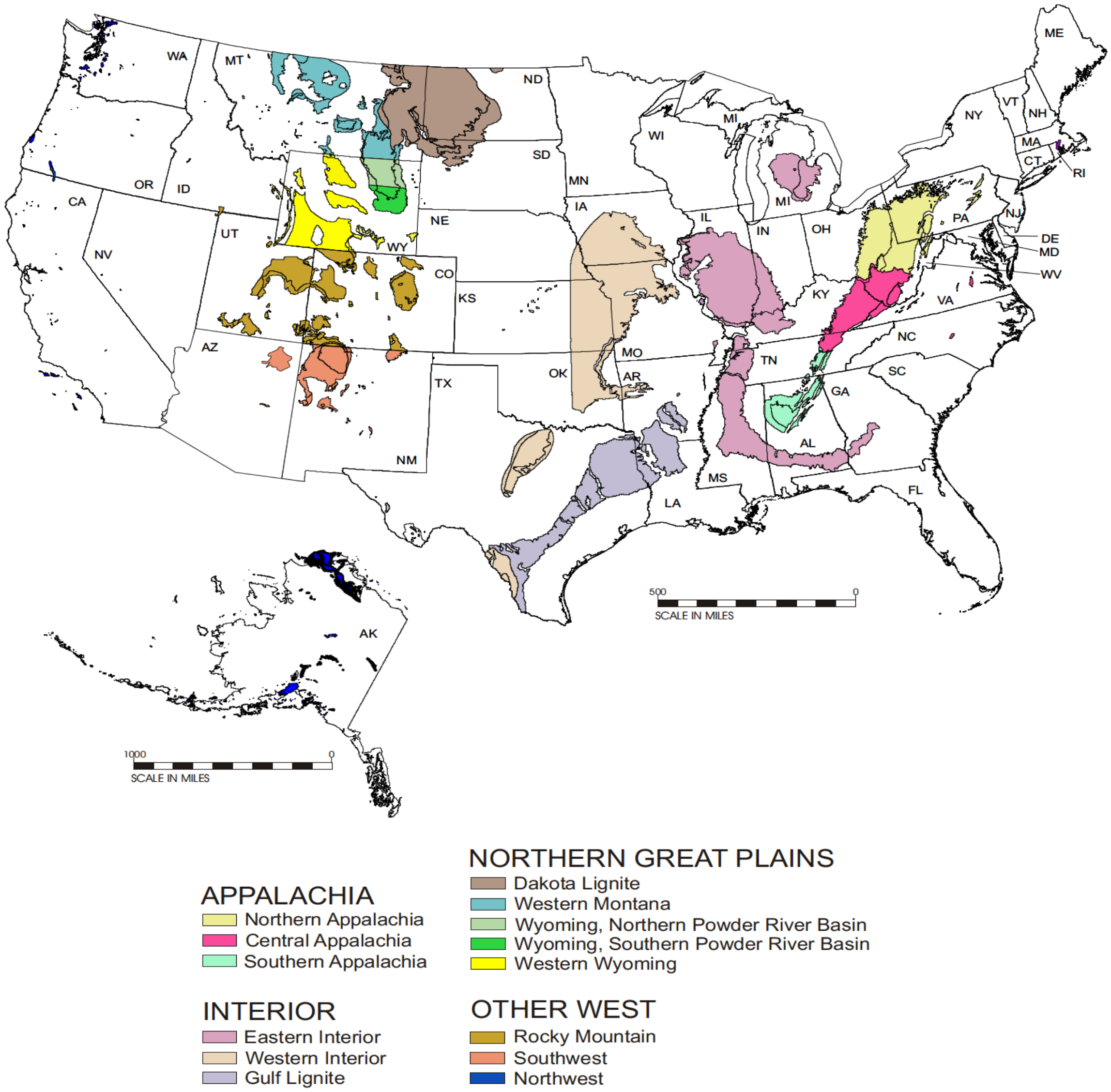
Supply Region	2009	2015	2020	2025	2030	2035	Average Annual Growth 09-35
Northern Appalachia	3.53	3.49	3.46	3.41	3.34	3.28	-0.3%
Central Appalachia	2.42	2.08	1.92	1.78	1.69	1.61	-1.6%
Southern Appalachia	2.01	1.82	1.69	1.57	1.49	1.42	-1.3%
Eastern Interior	4.08	4.12	4.13	4.11	4.09	4.05	0.0%
Western Interior	2.58	2.61	2.61	2.61	2.61	2.61	0.0%
Gulf Lignite	6.40	6.56	6.39	6.24	6.08	5.93	-0.3%
Dakota Lignite	14.90	14.51	14.88	15.25	15.64	16.03	0.3%
Western Montana	16.80	14.92	15.98	15.97	16.29	16.78	0.0%
Wyoming, Northern Powder River Basin	32.13	31.64	30.86	30.10	29.35	28.63	-0.4%
Wyoming, Southern Powder River Basin	34.34	33.83	32.99	32.17	31.38	30.60	-0.4%
Western Wyoming	7.00	6.90	7.04	7.16	7.48	7.67	0.4%
Rocky Mountain	5.48	5.59	5.58	5.54	5.49	5.44	0.0%
Arizona/New Mexico	8.60	8.41	8.55	8.62	8.68	8.73	0.1%
Alaska/Washington	6.58	6.58	6.58	6.58	6.58	6.58	0.0%
U.S. Average	5.61	6.03	5.97	6.02	6.14	6.12	0.3%

Source: U.S. Energy Information Administration, *AEO2011* National Energy Modeling System run REF2011.D020911A.

The key assumptions underlying the coal distribution modeling are:

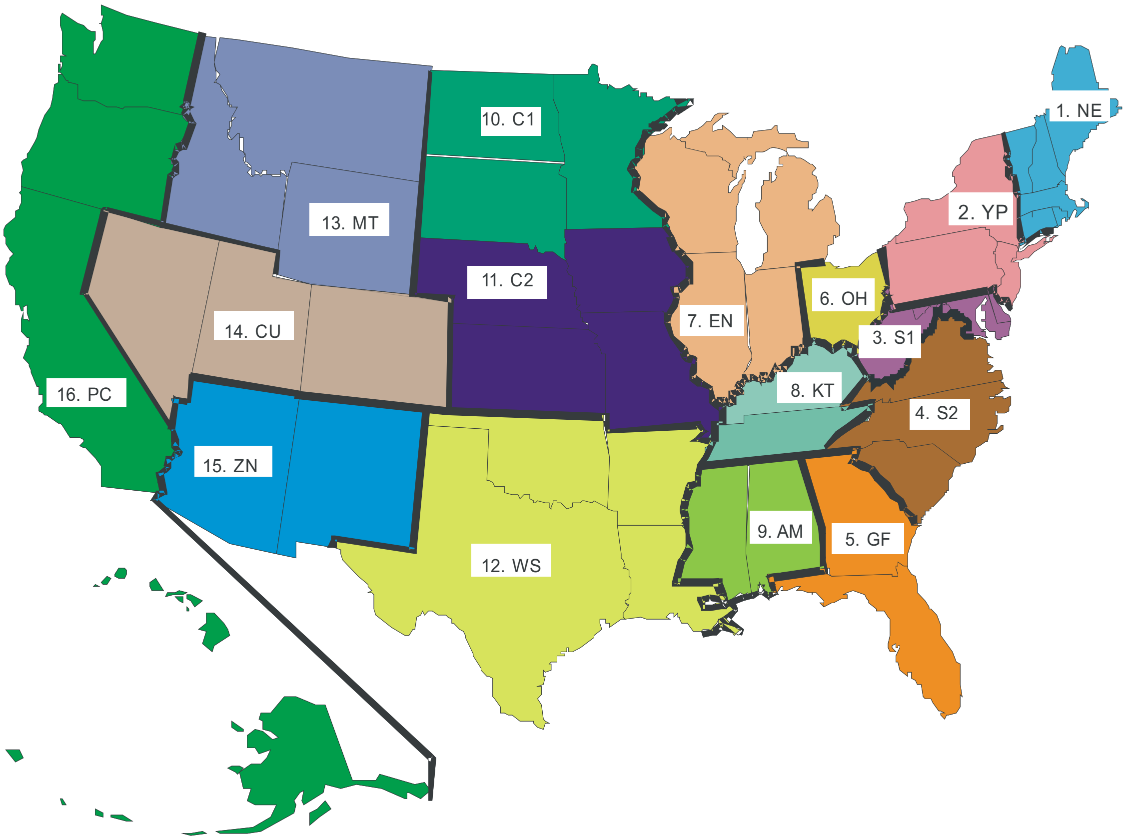
- Base-year (2009) transportation costs are estimates of average transportation costs for each origin-destination pair without differentiation by transportation mode (rail, truck, barge, and conveyor). These costs are computed as the difference between the average delivered price for a demand region (by sector and for export) and the average minemouth price for a supply curve. Delivered price data are from Form EIA-3, "Quarterly Coal Consumption Report-Manufacturing Plants", Form EIA-5, "Quarterly Coke Consumption and Quality Report, Coke Plants", Form EIA-923, "Power Plant Operations Report", and the U.S. Bureau of the Census' "Monthly Report EM-545". Minemouth price data are from Form EIA-7A, "Coal Production Report".
- For the electricity sector only, a two-tier transportation rate structure is used for those regions which, in response to rising demands or changes in demands, may expand their market share beyond historical levels. The first-tier rate is representative of the historical average transportation rate. The second-tier transportation rate is used to capture the higher cost of expanded shipping distances in large demand regions. The second tier is also used to capture costs associated with the use of subbituminous coal at units that were not originally designed for its use. This cost is estimated at $0.10 per million Btu (2000 dollars) [3].
- Coal transportation costs, both first- and second-tier rates, are modified over time by two regional (east and west) transportation indices. The indices, calculated econometrically, are measures of the change in average transportation rates, for coal shipments on a tonnage basis, that occurs between successive years for coal shipments. An east index is used for coal originating from eastern supply regions while a west index is used for coal originating from western supply regions. The east index is a function of railroad productivity, the user cost of capital for railroad equipment, and national average diesel fuel price. The user cost of capital for railroad equipment is calculated from the producer price index (PPI) for railroad equipment, and accounts for the opportunity cost of money used to purchase equipment, depreciation occurring as a result of use of the equipment (assumed at 10 percent), less any capital gain associated with the worth of the equipment. In calculating the user cost of capital, three percentage points are added to the cost of borrowing in order to account for the possibility that greenhouse gas emissions may be regulated in the future. The west index is a function of railroad productivity, investment, and western share of national coal consumption. The indices are universally applied to all domestic coal transportation movements within the CMM. In the *AEO2011* Reference case, eastern coal transportation rates are projected to be the same in 2035 and western rates are projected to be 6 percent higher in 2035 compared to 2009.

Figure 10. Coal Supply Regions



Source: U.S. Energy Information Administration, Office of Enery Analysis

Figure 11. Coal Demand Regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. S1	WV,MD,DC,DE
4. S2	VA,NC,SC
5. GF	GA,FL
6. OH	OH
7. EN	IN,IL,MI,WI
8. KT	KY,TN

Region Code	Region Content
9. AM	AL,MS
10. C1	MN,ND,SD
11. C2	IA,NE,MO,KS
12. WS	TX,LA,OK,AR
13. MT	MT,WY,ID
14. CU	CO,UT,NV
15. ZN	AZ,NM
16. PC	AK,HI,WA,OR,CA

Source: U.S. Energy Information Administration, Office of Energy Analysis

- For the projection period, the explanatory variables are assumed to have varying impacts on the calculation of the indices. For the west, investment is the analogous variable to the user cost of capital of railroad equipment. The investment value and the PPI for rail equipment which is used to derive the user cost of capital increase with an increase in national ton-miles (total tons of coal shipped multiplied by the average distance). Increases in investment (west) or the user cost of capital for railroad equipment (east) cause projected transportation rates to increase. For both the east and the west, any related financial savings due to productivity improvements are assumed to be retained by the railroads and are not passed on to shippers in the form of lower transportation rates. For that reason, productivity is held flat for the projection period for both regions. For the east for the projection period, diesel fuel is removed from the equation in order to avoid double-counting the influence of diesel fuel costs with the impact of the fuel surcharge program. The transportation rate indices for seven *AEO2011* cases are shown in Table 12.2.

Table 12.2. Transportation rate multipliers
constant dollar index, 2009=1.000

Scenario	Region:	2009	2015	2020	2025	2030	2035
Reference Case	East	1.000	1.0096	1.0194	1.0146	1.0074	1.0037
	West	1.000	0.9621	0.9831	1.0144	1.0388	1.0578
High Resource Price	East	1.000	1.0296	1.0252	1.0239	1.0145	1.0033
	West	1.000	0.9532	0.9749	1.0187	1.0760	1.1068
Low Resource Price	East	1.000	1.0176	1.0234	1.0113	1.0024	1.0021
	West	1.000	0.9683	0.9869	1.0203	1.0380	1.0450
High Economic Growth	East	1.000	1.0156	1.0171	1.0077	1.0088	1.0004
	West	1.000	0.9674	0.9947	1.0319	1.0646	1.0729
Low Economic Growth	East	1.000	1.0094	1.0211	1.0182	1.0158	1.0129
	West	1.000	0.9592	0.9734	1.0016	1.0152	1.0261
High Coal Cost	East	1.000	1.0600	1.1200	1.1700	1.2100	1.2600
	West	1.000	1.0200	1.0900	1.1700	1.2500	1.3200
Low Coal Cost	East	1.000	0.9600	0.9200	0.8700	0.8100	0.7600
	West	1.000	0.9200	0.8900	0.8700	0.8300	0.7900

Source: Projections: U.S. Energy Information Administration, National Energy Modeling System runs REF2011.D020911A, HP2011HNO.D022511A, LP2011LNO.D022511A, HM2011.D020911A, LM2011.D020911A, HCCST11.D020911A, LCCST11.D020911A. Based on methodology described in *Coal Market Module of the National Energy Modelling System 2011*, DOE/EIA-M066(2011) (Washington, DC, 2011).

- Major coal rail carriers have implemented fuel surcharge programs in which higher transportation fuel costs have been passed on to shippers. While the programs vary in their design, the Surface Transportation Board (STB), the regulatory body with limited authority to oversee rate disputes, recommended that the railroads agree to develop some consistencies among their disparate programs and likewise recommended closely linking the charges to actual fuel use. The STB cited the use of a mileage-based program as one means to more closely estimate actual fuel expenses.
- For *AEO2011*, representation of a fuel surcharge program is included in the coal transportation costs. For the west, the methodology is based on BNSF Railway Company's mileage-based program. The surcharge becomes effective when the projected nominal distillate price to the transportation sector exceeds $1.25 per gallon. For every $0.06 per gallon increase above $1.25, a $0.01 per carload mile is charged. For the east, the methodology is based on CSX Transportation's mileage-based program. The surcharge becomes effective when the projected nominal distillate price to the transportation sector exceeds $2.00 per gallon. For every $0.04 per gallon increase above $2.00, a $0.01 per carload mile is charged. The number of tons per carload and the number of miles vary with each supply and demand region combination and are a pre-determined model input. The final calculated surcharge (in constant dollars per ton) is added to the escalator-adjusted transportation rate. For every projection year, it is assumed that 100 percent of all coal shipments are subject to the surcharge program.
- Coal contracts in the CMM represent a minimum quantity of a specific electricity coal demand that must be met by a unique coal supply source prior to consideration of any alternative sources of supply. Base-year (2009) coal contracts between coal producers and electricity generators are estimated on the basis of receipts data reported by generators on the EIA-923, "Power Plant Operations Report". Coal contracts are specified by CMM supply region, coal type, demand region, and whether or not a unit has flue gas desulfurization equipment. Coal contract quantities are reduced over time on the basis of contract duration data from information reported on the Form EIA-923, "Power Plant Operations Report", historical patterns of coal use, and information obtained from various coal and electric power industry publications and reports.
- Electric generation demand received by the CMM is subdivided into "coal groups" representing demands for different sulfur and thermal heat content categories. This process allows the CMM to determine the economically optimal blend of different coals to minimize delivered cost, while meeting emissions requirements. Similarly, nongeneration demands are subdivided into subsectors with their own coal groups to ensure that, for example, lignite is not used to meet a coking coal demand.

- Coal-to-liquids (CTL) facilities are assumed to be economic when low-sulfur distillate prices reach high enough levels. These plants are assumed to be co-production facilities with generation capacity of 845 MW(300 MW for the grid and 545 MW to support the conversion process) and the capability of producing 50,000 barrels of liquid fuel per day. The technology assumed is similar to an integrated gasification combined cycle, first converting the coal feedstock to gas, and then subsequently converting the syngas to liquid hydrocarbons using the Fisher-Tropsch process. Of the total amount of coal consumed at each plant, 46 percent of the energy input is retained in the product with the remaining energy used for conversion and for the production of power sold to the grid. Beginning with *AEO2010*, coal-biomass-to-liquids (CBTL) capability was incorporated into the NEMS structure. For *AEO2011*, these facilities are assumed to have a capacity of 602MW (150 MW for the grid and 452 MW to support the conversion process) and the capability of producing 30,000 barrels of liquid fuel per day. Eighty percent of the energy input is derived from coal with the remaining 20 percent derived from biomass. CTL and CBTL facilities produce paraffinic naptha used in plastics production and blendable naptha used in motor gasoliine (together about 43 percent of the total by volume) and distillate fuel oil also known as diesel fuel (about 57 percent).

Coal imports and exports

Coal imports and exports are modeled as part of the CMM's linear program that provides annual projections of U.S. steam and metallurgical coal exports, in the context of world coal trade. The linear program determines the pattern of world coal trade flows that minimize the production and transportation costs of meeting U.S. import demand and a pre-specified set of regional world coal import demands. It does this subject to constraints on export capacity and trade flows.

The key assumptions underlying coal export modeling are:

- Coal buyers (importing regions) tend to spread their purchases among several suppliers in order to reduce the impact of potential supply disruptions, even though this may add to their purchase costs. Similarly, producers choose not to rely on any one buyer and instead endeavor to diversify their sales.
- Coking coal is treated as homogeneous. The model does not address quality parameters that define coking coals. The values of these quality parameters are defined within small ranges and affect world coking coal flows very little.

Data inputs for coal trade modeling:

- World steam and metallurgical coal import demands for the *AEO2011* cases are shown in Tables 12.3 and 12.4. U.S. coal exports are determined, in part, by these estimates of world coal import demand.
- Step-function coal export supply curves for all non-US supply regions. The curves provide estimates of export prices per metric ton, inclusive of minemouth and inland freight costs, as well as the capacities for each of the supply steps.
- Ocean transportation rates (in dollars per metric ton) for feasible coal shipments between international supply regions and international demand regions. The rates take into account typical vessel sizes and route distances in thousands of nautical miles between supply and demand regions.

Coal quality

Each year the values of base year coal production, heat, sulfur and mercury content and carbon dioxide emissions for each coal source in CMM are calibrated to survey data. Surveys used for this purpose are the Form EIA-923, a survey of the origin, cost and quality of fossil fuels delivered to generating facilities, and the Form EIA-5 which records the origin, cost and quality of coal delivered to domestic industrial consumers. Estimates of coal quality for the export and residential/commercial sectors are made using the survey data for coal delivered to coking coal and industrial steam coal consumers. Mercury content data for coal by supply region and coal type, in units of pounds of Mercury per trillion Btu, shown in Table 71, were derived from shipment-level data reported by electricity generators to the Environmental Protection Agency in its 1999 Information Collection Request. The database included approximately 40,500 Mercury samples reported for 1,143 generating units located at 464 coal-fired facilities. Carbon dioxide emission factors for each coal type are shown in Table 12.5 in pounds of carbon dioxide emitted per million Btu [4].

The CMM projects steam and metallurgical coal trade flows from 17 coal-exporting regions of the world to 20 import regions for three coal types (coking, bituminous steam, and subbituminous). It includes five U.S. export regions and four U.S. import regions.

Table 12.3. World steam coal import demand by import region
million metric tons of coal equivalent

	2009	2015	2020	2025	2030	2035
The Americas	42.3	51.7	56.3	65.9	77.1	79.9
United States[3]	16.3	23.9	29.7	37.4	45.0	44.4
Canada	8.2	5.4	3.6	4.1	4.0	4.0
Mexico	3.0	5.5	6.4	7.9	11.0	12.1
South America	14.8	16.9	16.6	16.6	17.0	19.4
Europe	163.9	194.1	178.5	174.0	171.4	171.1
Scandinavia	10.6	8.0	6.5	5.8	5.0	4.5
U.K./Ireland	35.6	42.8	28.7	29.6	31.0	32.3
Germany/Austria	33.7	38.7	38.5	37.5	36.5	35.5
Other NW Europe	23.1	22.8	22.8	20.8	20.0	19.1
Iberia	19.4	21.6	20.5	19.1	17.6	16.3
Italy	12.7	25.3	27.1	27.1	27.1	27.1
Med/E Europe	28.8	34.9	34.4	34.1	34.2	36.3
Asia	314.3	410.4	435.0	455.9	493.7	553.0
Japan	94.1	84.5	82.8	79.4	77.8	76.1
East Asia	112.3	117.8	121.4	125.2	132.9	157.3
China/Hong Kong	42.5	89.0	89.0	89.0	97.4	105.9
ASEAN	32.0	41.9	50.6	60.5	67.4	77.3
Indian Sub	33.4	77.2	91.2	101.8	118.2	136.4
TOTAL	520.5	656.2	669.8	695.8	742.2	804.0

[1]Import Regions: South America: Argentina, Brazil, Chile, Puerto Rico; Scandinavia: Denmark, Finland, Norway, Sweden; Other NW Europe: Belgium, France, Luxembourg, Netherlands; Iberia: Portugal, Spain; Med/E Europe: Algeria, Bulgaria, Croatia, Egypt, Greece, Israel, Malta, Morocco, Romania, Tunisia, Turkey; East Asia: North Korea, South Korea, Taiwan; ASEAN: Malaysia, Philippines, Thailand; Indian Sub: Bangladesh, India, Iran, Pakistan, Sri Lanka.
[2]The base year of the world trade projection for coal is 2009.
[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
Notes: One "metric ton of coal equivalent" equals 27.78 million Btu. Totals may not equal sum of components due to independent rounding.

Table 12.4. World metallurgical coal import demand by import region
million metric tons of coal equivalent

	2009	2015	2020	2025	2030	2035
The Americas	20.0	22.8	27.5	32.8	38.8	46.2
United States	1.3	1.3	1.3	1.3	1.3	1.3
Canada	2.3	2.9	2.8	2.7	2.7	2.6
Mexico	1.0	1.0	1.0	1.0	1.0	1.0
South America	15.4	17.6	22.3	27.7	33.8	41.3
Europe	64.0	55.3	55.7	55.7	56.0	56.1
Scandinavia	2.7	2.4	2.7	2.7	2.7	2.7
U.K./Ireland	6.5	7.3	7.3	7.3	7.3	7.3
Germany/Austria	11.5	9.3	9.3	9.2	9.2	9.2
Other NW Europe	17.2	14.9	14.7	14.5	14.4	14.2
Iberia	3.8	4.0	3.9	3.8	3.8	3.6
Italy	7.4	7.4	7.4	7.3	7.2	7.3
Med/E Europe	14.9	10.0	10.4	10.9	11.4	11.8
Asia	141.2	192.6	212.7	219.6	225.5	234.4
Japan	81.4	72.3	67.5	65.5	63.6	60.7
East Asia	31.4	33.9	34.1	35.3	36.4	37.6
China/Hong Kong	2.2	40.5	38.5	38.5	38.5	38.5
ASEAN[4]	0.0	0.0	0.0	0.0	0.0	0.0
Indian Sub	26.2	45.9	72.6	80.3	87.0	97.6
TOTAL	225.2	270.7	295.9	308.1	320.3	336.7

[1]Import Regions: South America: Argentina, Brazil, Chile, Puerto Rico; Scandinavia: Denmark, Finland, Norway, Sweden; Other NW Europe: Belgium, France, Luxembourg, Netherlands; Iberia: Portugal, Spain; Med/E Europe: Algeria, Bulgaria, Croatia, Egypt, Greece, Israel, Malta, Morocco, Romania, Tunisia, Turkey; East Asia: North Korea, South Korea, Taiwan; ASEAN: Malaysia, Philippines, Thailand; Indian Sub: Bangladesh, India, Iran, Pakistan, Sri Lanka.
[2]The base year of the world trade projection for coal is 2009.
[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[4]Malaysia, Phillipines, and Thailand are not expected to import significant amounts of metallurgical coal in the projection.
Notes: One "metric ton of coal equivalent" equals 27.78 million Btu. Totals may not equal sum of components due to independent rounding.

Legislation and regulations

The *AEO2011* is based on current laws and regulations in effect before October 31, 2010.

The *AEO2011* Reference case incorporates provisions of the Clean Air Act Amendments of 1990 as they apply to SO2 and NOx emissions.

The Clean Air Mercury Rule (CAMR) and the Clean Air Interstate Rule (CAIR) are additional rules related to coal emissions. These rules were promulgated by the EPA but vacated by the courts in February and July 2008, respectively. CAIR addresses further SO2 emissions and seasonal and annual NOx emissions while CAMR addresses mercury emissions. As a result of the court ruling, CAMR is not included in the *AEO2011* Reference case and, in the absence of a cap-and-trade system, mercury allowance prices are not modeled. However, with or without CAMR, many States were planning to implement mercury rules of their own. For those States, the effects of state laws are approximated and modeled for the *AEO2011*. CAIR, however, was temporarily reinstated by the courts in December 2008 and is included in *AEO2011*.

Table 12.5. Production, heat content, sulfur, mercury and carbon dioxide emission factors by coal type and region

Coal Supply Region	States	Coal Rank and Sulfur Level	Mine Type	2009 Production (Million Short Tons)	Heat Content (Million Btu per Short Ton)	Sulfur Content (Pounds Per Million Btu)	Mercury Content (Pounds per Trillion Btu)	CO2 (Pounds Per Million Btu)
Northern Appalachia	PA, OH, MD, WV(North)	Metallurgical	Underground	4.6	26.33	0.68	N/A	204.7
		Mid-Sulfur Bituminous	All	48.3	25.32	1.33	11.17	204.7
		High-Sulfur Bituminous	All	74.6	24.75	2.60	11.67	204.7
		Waste Coal (Gob and Culm)	Surface	12.4	12.25	3.01	63.9	204.7
Central Appalachia	KY(East),WV (South), VA, TN(North)	Metallurgical	Underground	38.0	26.33	0.67	N/A	206.4
		Low-Sulfur Bituminous	All	25.8	24.86	0.54	5.61	206.4
		Mid-Sulfur Bituminous	All	132.9	24.75	0.91	7.58	206.4
Southern Appalachia	AL, TN(South)	Metallurgical	Underground	8.8	26.33	0.52	N/A	204.7
		Low-Sulfur Bituminous	All	0.7	24.66	0.49	3.87	204.7
		Mid-Sulfur Bituminous	All	9.7	24.06	1.25	10.15	204.7
East Interior	IL, IN, KY(West), MS	Mid-Sulfur Bituminous	All	14.1	22.71	1.08	5.6	203.1
		High-Sulfur Bituminous	All	88.8	22.84	2.60	6.35	203.1
		Mid-Sulfur Lignite	Surface	3.4	10.21	0.92	14.11	216.5
West Interior	IA, MO, KS, AR, OK, TX (Bit)	High-Sulfur Bituminous	Surface	1.6	22.24	2.12	21.55	202.8
Gulf Lignite	TX (Lig), LA	Mid-Sulfur Lignite	Surface	23.5	13.35	1.24	14.11	212.6
		High-Sulfur Lignite	Surface	15.2	12.38	2.60	15.28	212.6
Dakota Lignite	ND, MT(Lig)	Mid-Sulfur Lignite	Surface	30.3	13.30	1.12	8.38	219.3
Western Montana	MT(Sub)	Low-Sulfur Subbituminous	Underground	0.8	19.22	0.39	5.06	215.5
		Low-Sulfur Subbituminous	Surface	18.9	18.29	0.39	5.06	215.5
		Mid-Sulfur Subbituminous	Surface	19.5	17.18	0.78	5.47	215.5
Northern Wyoming	WY(Northern Powder River Basin)	Low-Sulfur Subbituminous	Surface	170.7	16.84	0.37	7.08	214.3
		Mid-Sulfur Subbituminous	Surface	4.0	16.14	0.74	7.55	214.3
Southern Wyoming	WY (Southern Powder River Basin)	Low-Sulfur Subbituminous	Surface	242.4	17.57	0.32	5.22	214.3

Table 12.5. Production, heat content, sulfur, mercury and carbon dioxide emission factors by coal type and region (cont)

Coal Supply Region	States	Coal Rank and Sulfur Level	Mine Type	2009 Production (Million short Tons	Heat Content (Million Btu per Short Ton)	Sulfur Content (Pounds Per Million Btu)	Mercury Content (Pounds per Trillion Btu)	CO2 (Pounds Per Million Btu)
Western Wyoming	WY (Other basins, excluding Powder River Basin)	Low-Sulfur Subbituminous	Underground	3.5	18.65	0.62	2.19	214.3
		Low-Sulfur Subbituminous	Surface	4.7	19.06	0.47	4.06	214.3
		Mid-Sulfur Subbituminous	Surface	5.8	19.25	0.85	4.35	214.3
Rocky Mountain	CO, UT	Metallurgical	Underground	--	26.28	0.52	N/A	209.6
		Low-Sulfur Bituminous	Underground	43.9	22.80	0.42	3.82	209.6
		Low-Sulfur Subbituminous	Surface	6.1	20.18	0.42	2.04	212.8
Southwest	AZ, NM	Low-Sulfur Bituminous	Surface	7.4	21.50	0.59	4.66	207.1
		Mid-Sulfur Subbituminous	Surface	18.7	18.27	0.92	7.18	209.2
		Mid-Sulfur Bituminous	Underground	6.5	19.36	0.68	7.18	207.1
Northwest	WA, AK	Low-Sulfur Subbituminous	Surface	1.9	16.16	0.31	6.99	216.1

--indicates zero production in 2009.
N/A = not available.
Source: U.S. Energy Information Administration, Form EIA-3, "Quarterly Coal Consumption Report—Manufacturing Plants"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-6A, "Coal Distribution Report—Annual"; Form EIA-7A, "Coal Production Report", and Form EIA-923, "Power Plant Operations Report". U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM-545." U.S. Environmental Protection Agency, Emission Standards Division, Information Collection Request for Electric Utility Steam Generating Unit, Mercury Emissions Information Collection Effort (Research Triangle Park, NC, 1999). U.S. Environmental Protection Agency, "ANNEX 2 Methodology and Data for Estimating CO2 Emissions from Fossil Fuel Combustion", Table A-38, web site http://epa.gov/climatechange/emissions/downloads11/US-GHG-Inventory-2011-Annex-2.pdf.

The Energy Improvement and Extension Act of 2008 (EIEA) was passed in October 2008 as part of the Emergency Economic Stabilization Act of 2008. Subtitle B provides investment tax credits for various projects sequestering CO2. In the *AEO2011* Reference case, these provisions are assumed to result in 1 gigawatt of advanced coal-fired capacity with carbon capture and sequestration by 2017. Subtitle B which extends the phaseout of payments by coal producers to the Black Lung Disability Trust Fund from 2013 to 2018 is also modeled in the *AEO2011*.

Title IV, under Energy and Water Development, of the American Recovery and Revitalization Act of 2009 (ARRA), provides $3.4 billion for additional research and development on fossil energy technologies. This includes $800 million to fund projects under the Clean Coal Power Initiative (CCPI) program, focusing on projects that capture and sequester greenhouse gases. In July 2009, a total of $408 million, was allocated to two projects, the Basin Electric Power Cooperative's Antelope Valley Station in North Dakota and the Hydrogen Energy Project in California, to collectively demonstrate the capability to capture 3,000,000 tons of carbon dioxide per year. In December 2009, three additional project awards were announced through the CCPI program and will receive part of their government funding through ARRA. These projects include American Electric Power's Mountaineer plant in West Virginia (235 megawatt flue gas stream), Alabama Power's Barry plant in Alabama (160 megawatt flue gas stream), and a new plant to be built by Summit Texas Clean Energy in Texas. (Alabama Power has since withdrawn from the CCPI). To reflect the impact of this provision, the *AEO2011* Reference case assumes that an additional 1 gigawatt of coal capacity with CCS will be stimulated by 2017.

Title XVII of the Energy Policy Act of 2005 authorizes loan guarantees for projects that avoid, reduce, or sequester greenhouse gasses. For *AEO2011*, the 2 gigawatts of advanced coal-fired capacity with carbon capture and sequestration assumed for EIEA and ARRA are also assumed to benefit from these loan guarantees.

Beginning in 2008, electricity generating units of 25 megawatts or greater were required to hold an allowance for each ton of CO2 emitted in 10 Northeastern States as part of the Regional Greenhouse Gas Initiative (RGGI). The States participating in RGGI include Connecticut, Maine, Maryland, Massachusetts, Rhode Island, Vermont, New York, New Jersey, New Hampshire, and Delaware. RGGI is modeled in *AEO2011* as an emissions reduction for the Middle Atlantic region.

On April 1, 2010, the EPA issued a memorandum establishing interim guidelines to several of its regional offices for monitoring the compliance of surface coal mining operations in Appalachia, The guidellines relate primarily to the ongoing controversy over use of the mountaintop removal method at a number of surface coal mining operations in Central Appalachia primarily in southern West Virginia and eastern Kentucky. While the guidelines propose a more rigorous review for all new surface coal mines in Appalachia, the EPA indicates that the practice of valley fills, primarily associated with the mountaintop removal method, is the aspect of Appalachian coal mining that will be most scrutinized. The impact of the EPA's interim guidelines for surface coal mining operations in Appalachia is represented by downward adjustments to the coal mining productivity assumptions for Central Appalachian surface mines. The revised productivity levels, roughly 15 to 20 percent lower than those that would have been used for a case without the EPA's new permit review guidelines, are based on the assumption that average productivity for surface mining operations in Central Appalachia will decline gradually toward the productivity levels for smaller surface mines in the region as a result of the more restrictive guidelines for overburden management at large mountaintop mining operations.

Coal alternative cases

Coal Cost cases

In the Reference case, coal mine labor productivity is assumed to decline on average by 0.3 percent per year through 2035 while miner wage rates and mine equipment costs remain constant in 2009 dollars. Eastern and Western transportation rates are flat and 6 percent higher, respectively, in 2035 compared to 2009. In two alternative coal cost cases, productivity, average miner wages, equipment cost, and transportation rate assumptions were modified for 2010 through 2035 in order to examine the impacts on U.S. coal supply, demand, distribution and prices.

In the Low Mining Cost case, coal mine labor productivity is assumed to increase at an average rate of 3.3 percent per year through 2035. Coal mining wages, mine equipment costs, and other mine suppy costs are all assumed to be about 25 percent lower by 2035 in real terms in the Low Coal Cost case. Coal transportation rates, excluding the impact of fuel surcharges, are assumed to be 25 percent lower by 2035.

In the High Mining Cost case, coal mine labor productivity is assumed to decline at an average rate of 2.9 percent per year through 2035. Coal mining wages, mine equipment costs, and other mine supply costs are assumed to be about 30 percent higher by 2035. Compared to the Reference case, coal transportation rates are assumed to be 25 percent higher by 2035. The low and high coal cost cases represent fully integrated NEMS runs, with feedback from the Macroeconomic Activity, International, supply, conversion, and end-use demand modules.

No Greenhouse Gas Concern case

In the Reference case, to reflect the market reaction to potential future GHG regulation, a 3-percentage-point increase in the cost of capital for investments in new coal-fired power plants without carbon capture and sequestration technology and new coal-to-liquids plants is assumed. These assumptions affect cost evaluations for the construction of new capacity but not the actual operating costs for new existing plants. This adjustment was first implemented for *AEO2009*.

The No GHG concern case excludes the 3-percentage point increase in the cost of capital.

Notes and sources

[1] Energy Information Administration, The U.S. Coal Industry, 1970-1990: Two Decades of Change, DOE/EIA-0559, (Washington, DC, November 1992).

[2] Stanley C. Suboleski, et.al., Central Appalachia: Coal Mine Productivity and Expansion, Electric Power Research Institute, EPRI IE-7117, (September 1991).

[3] The estimated cost of switching to subbituminous coal, $0.10 per million Btu (2000 dollars), was derived by Energy Ventures Analysis, Inc. and was recommended for use in the CMM as part of an Independent Expert Review of the Annual Energy Outlook 2002's Powder River Basin production and transportation rates. Barbaro, Ralph and Seth Schwartz. Review of the Annual Energy Outlook 2002 Reference Case Forecast for PRB Coal, prepared for the Energy Information Administration (Arlington, VA: Energy Ventures Analysis, Inc., August 2002).

[4] U.S. Environmental Protection Agency, "Climate Change—Regulatory Initiative: Greenhouse Gas Reporting Program", website www.epa.gov/climatechange/emissions/.

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Renewable Fuels Module

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The NEMS Renewable Fuels Module (RFM) provides natural resources supply and technology input information for projections of new central-station U.S. electricity generating capacity using renewable energy resources. The RFM has seven submodules representing various renewable energy sources: biomass, geothermal, conventional hydroelectricity, landfill gas, solar thermal, solar photovoltaics, and wind [1].

Some renewables, such as landfill gas (LFG) from municipal solid waste (MSW) and other biomass materials, are fuels in the conventional sense of the word, while others, such as water, wind, and solar radiation, are energy sources that do not involve the production or consumption of a fuel. Commercial market penetration of renewable technologies varies widely. Hydroelectric power, one of the oldest electric generation technologies, accounts for roughly 6% of electric power generation; in newer power systems using biomass, geothermal, LFG, solar, or wind energy contribute a combined 4%.

The submodules of the RFM interact primarily with the Electricity Market Module (EMM). Because of the high level of integration with the EMM, the final outputs (levels of consumption and market penetration over time) for renewable energy technologies are largely dependent upon the EMM. Because some types of biomass fuel can be used for either electricity generation or for the production of liquid fuels, such as ethanol, there is also some interaction with the Petroleum Market Module (PMM), which contains additional representation of some biomass feedstocks that are used primarily for liquid fuels production.

Projections for residential and commercial grid-connected photovoltaic systems are developed in the end-use demand modules and not in the RFM; see the Distributed Generation and Combined Heat and Power descriptions in the "Commercial Demand Module" section of the report.

Key assumptions

Nonelectric renewable energy uses

In addition to projections for renewable energy used in central station electricity generation, the *AEO2011* contains projections of nonelectric renewable energy uses for industrial and residential wood consumption, solar residential and commercial hot water heating, biofuels blending in transportation fuels, and residential and commercial geothermal (ground-source) heat pumps. Assumptions for their projections are found in the residential, commercial, industrial, and petroleum marketing module sections of this report. Additional minor renewable energy applications occurring outside energy markets, such as direct solar thermal industrial applications or direct lighting, off-grid electricity generation, and heat from geothermal resources used directly (e.g., district heating and greenhouses) are not included in the projections.

Electric power generation

The RFM considers only grid-connected central station electricity generation systems. The RFM submodules that interact with the EMM are the central station grid-connected biomass, geothermal, conventional hydroelectricity, landfill gas, solar (thermal and photovoltaic), and wind submodules, which provide specific data or estimates that characterize the respective resource. A set of technology cost and performance values is provided directly to the EMM and is central to the build and dispatch decisions of the EMM. The technology cost and performance values are summarized in Table 8.2 in the chapter discussing the EMM. Overnight capital costs are presented in Table 13.1.

Table 13.1. Overnight capital cost characteristics for renewable energy generating technologies in three cases
2009$k/W

Technology	Year	Reference	High Cost Renewable[1]	Low Cost Renewable
Geothermal[2]	2010	2,482	2,482	1,985
	2015	2,481	2,560	1,969
	2025	2,101	2,305	1,594
	2035	1,598	1,917	1,170
Hydroelectric[2]	2010	2,221	2,221	1,771
	2015	2,259	2,273	1,733
	2025	1,991	2,056	1,355
	2035	1,601	1,705	960
Photovoltaic	2010	4,697	4,697	3,794
	2015	4,528	4,834	3,494
	2025	3,394	4,351	2,325
	2035	2,336	3,612	1,470
Solar Thermal Electric	2010	4,636	4,636	3,680
	2015	3,740	4,742	2,963
	2025	2,828	4,316	1,967
	2035	1,871	3,602	1,199
Biomass[3]	2010	3,718	3,718	2,182
	2015	3,755	3,816	3,010
	2025	3,250	3,417	2,296
	2035	2,562	2,804	1,643
Offshore Wind	2010	6,048	6,048	5,185
	2015	5,729	5,921	4,712
	2025	4,846	5,390	3,511
	2035	3,722	4,498	2,452
Onshore Wind[4]	2010	2,403	2,403	2,030
	2015	2,472	2,474	1,990
	2025	2,240	2,251	1,590
	2035	1,854	1,877	1,188

[1]Overnight capital cost (that is, excluding interest charges), plus contingency, learning, and technological optimism factors, excluding regional multipliers. A contingency allowance is defined by the American Association of Cost Engineers as the specific provision for unforeseeable elements of costs within a defined project scope. This is particularly important where previous experience has shown that unforeseeable events which will increase costs are likely to occur.
[2]Geothermal and Hydroelectric costs are specific to each plant site. Costs shown represent what the costs would be for the lowest cost site from the Northwest in 2010 if that site were available to be built in each of the years indicated.
[3]Biomass plants share significant components with similar coal-fired plants, these components continue to decline in cost in the Low Renewables case, although biomass-specific components (especially fuel handling components) do not see cost declines beyond the initial year.
[4]Wind costs are region specific. The table represents costs in the Northwest Power Pool region.
Source: U.S. Energy Information Administration. *AEO2011* National Energy Modeling System runs REF2011.D020911A, HIRENCST10.D011410A, and LORENCST10.D011510A.

Capital costs

Capital costs for renewable technologies are affected by several factors. Capital costs for technology to exploit some resources, especially geothermal, hydroelectric, and wind power resources, are assumed to be dependent on the quality, accessibility, and/or other site-specific factors in the areas with exploitable resources. These factors can include additional costs associated with reduced resource quality; need to build or upgrade transmission capacity from remote resource areas to load centers; or local impediments to permitting, equipment transport, and construction in good resource areas due to siting issues, inadequate infrastructure, or rough terrain.

Short-term cost adjustment factors increase technology capital costs as a result of a rapid U.S. buildup in a single year, reflecting limitations on the infrastructure (for example, limits on manufacturing, resource assessment, and construction expertise) to accommodate unexpected demand growth. These factors, which are applied to all new electric generation capacity, are a function of past production rates and are further described in The Electricity Market Module of the National Energy Modeling System: Model Documentation Report, available at http://www.eia.gov/analysis/model-documentation.cfm.

Aso assumed to affect all new capacity types are costs associated with construction commodities. Through the middle of this decade, the installed cost for most new plants was observed to increase. Although several factors contributed to this cost escalation, some of which may be more or less important to specific types of new capacity, much of the overall cost increase was correlated with increases in the cost of construction materials, such as bulk metals, specialty metals, and concrete. Capital costs are specifically linked to the projections for the metals producer price index found in the Macroeconomic Module of NEMS. Independent of the other two factors, capital costs for all electric generation technologies, including renewable technologies, are assumed to decline as a function of growth in installed capacity for each technology.

For a description of NEMS algorithms lowering generating technologies' capital costs as more units enter service (learning), see "Technological Optimism and Learning" in the EMM chapter of this report. A detailed description of the RFM is provided in the EIA publication, Renewable Fuels Module of the National Energy Modeling System, Model Documentation 2010, DOE/EIA-M069(2010) (Washington, DC, 2009).

Solar Electric Submodule

Background

The Solar Electric Submodule currently includes both concentrating solar power (thermal) and photovoltaics, including two solar technologies: 100 megawatt central-receiver type solar thermal (also referred to as "concentrating solar power" or CSP) without integrated energy storage and 150 megawatt fixed-tilt, flat plate photovoltaic (PV) technologies. PV is assumed available in all EMM regions, while CSP is available only in the Western regions with the arid atmospheric conditions that result in the most cost-effective capture of direct sunlight. Capital costs for both technologies are determined by EIA based on a report by R.W. Beck (see http://www.eia.gov/oiaf/beck_plantcosts/). Most other cost and performance characteristics are obtained from information provided by the National Renewable Energy Laboratory (NREL).

Assumptions

- Capacity factors for solar technologies are assumed to vary by time of day and season of the year, such that nine separate capacity factors are provided for each modeled region, three for time of day and for each of three broad seasonal groups (summer, winter, and spring/fall). Regional capacity factors vary from national averages based on climate and latitude.
- Because solar technologies are more expensive than other utility grid-connected technologies, early penetration will be driven by broader economic decisions such as the desire to become familiar with a new technology, environmental considerations, and the availability of limited Federal subsidies. Minimal market penetration is included by EIA as "floor" additions to new generating capacity (see "Supplemental and Floor Capacity Additions" below).
- Solar resources are well in excess of conceivable demand for new capacity; energy supplies are considered unlimited within regions (at specified daily, seasonal, and regional capacity factors). Therefore, solar resources are not estimated in NEMS. In the regions where CSP technology is not modeled, the level of direct, normal insolation (the kind needed for that technology) is assumed to be insufficient to make that technology commercially viable through the forecast horizon.
- NEMS represents the Energy Policy Act of 1992 (EPACT92) permanent 10-percent investment tax credit (ITC) for solar electric power generation by tax-paying entities. In addition, the current 30-percent ITC scheduled to expire at the end of 2016, is also represented to qualifying new capacity installations.

Wind-Electric Power Submodule

Background

Because of limits to windy land areas, wind is considered a finite resource, so the submodule calculates maximum available capacity by Electricity Market Module Supply Regions. The minimum economically viable average wind speed is about 14 mph, and wind speeds are categorized by annual average wind speed based on a classification system originally from the Pacific Northwest Laboratory. The RFM tracks wind capacity (megawatts) by resource quality, and costs within a region and moves to the next best wind resource when one category is exhausted. Wind resource data on the amount and quality of wind per EMM region come from the National Renewable Energy Laboratory [2]. The technological performance, cost, and other wind data used in NEMS are derived by EIA a report by R.W. Beck (see http://www.eia.gov/oiaf/beck_plantcosts/). Maximum wind capacity, capacity factors, and incentives are provided to the EMM for capacity planning and dispatch decisions. These form the basis on which the EMM decides how much power generation capacity is available from wind energy. The fossil-fuel heat rate equivalents for wind are used for energy consumption calculation purposes only.

Assumptions

- Only grid-connected (utility and nonutility) generation is included. Projections for distributed wind generation are included in the commercial and residential modules.
- In the wind submodule, wind supply costs are affected by three modeling measures: addressing (1) average wind speed, (2) distance from existing transmission lines, and (3) resource degradation, transmission network upgrade costs, and market factors.
- Available wind resource is reduced by excluding all windy lands not suited for the installation of wind turbines because of: excessive terrain slope (greater than 20 percent); reservation of land for non-intrusive uses (such as National Parks, wildlife refuges, and so forth); inherent incompatibility with existing land uses (such as urban areas, areas surrounding airports and water bodies, including offshore locations); insufficient contiguous windy land to support a viable wind plant (less than 5 square kilometers of windy land in a 100 square kilometer area). Half of the wind resource located on military reservations, U.S. Forest Service land, state forested land, and all non-ridge-crest forest areas are excluded from the available resource base to account for the uncertain ability to site projects at such locations. These assumptions are detailed in the Draft Final Report to EIA on Incorporation of Existing Validated Wind Data into NEMS, November 2003.
- Capital costs for wind technologies are assumed to increase in response to (1) declining natural resource quality, such as terrain slope, terrain roughness, terrain accessibility, wind turbulence, wind variability, or other natural resource factors, as the best sites are utilized (2) increasing cost of upgrading existing local and network distribution and transmission lines to accommodate growing quantities of remote wind power, and (3) market conditions, such as the increasing costs of alternative land uses, including aesthetic or environmental reasons. Capital costs are left unchanged for some initial share, then increased 10, 25, 50 percent, and finally 100 percent, to represent the aggregation of these factors.
- Proportions of total wind resources in each category vary by EMM region. For all EMM regions combined, about 1 percent of windy land (107 GW of 11,600 GW in total resource) is available with no cost increase, 3.4 percent (390 GW) is available with a 10 percent cost increase, 2 percent (240 GW) is available with a 25 percent cost increase, and over 90 percent is available with a 50 or 100 percent cost increase.
- Depending on the EMM region, the cost of competing fuels, and other factors, wind plants can be built to meet system capacity requirements or as a "fuel saver" to displace generation from existing capacity. For wind to penetrate as a fuel saver, its total capital and fixed operations and maintenance costs minus applicable subsidies must be less than the variable operating costs, including fuel, of the existing (non-wind) capacity. When competing in the new capacity market, wind is assigned a capacity credit that declines based on its estimated contribution to regional reliability requirements.
- Because of downwind turbulence and other aerodynamic effects, the model assumes an average spacing between turbine rows of 5 rotor diameters and a lateral spacing between turbines of 10 rotor diameters. This spacing requirement determines the amount of power that can be generated from wind resources, about 6.5 megawatts per square kilometer of windy land, and is factored into requests for generating capacity by the EMM.
- Capacity factors are assumed to increase to 46 percent in the best wind class resulting from taller towers, more reliable equipment, and advanced technologies. Capacity factors for each wind class are calculated as a function of overall wind market growth. The capacity factors are assumed to be limited to about 48 percent for a typical Class 6 site. As better wind resources are depleted, capacity factors are assumed to go down, corresponding with the use less desirable sites. By 2035, the typical wind plant build will have a somewhat lower capacity factor than those found in the best wind resource area.

- *AEO2011* does not allow plants constructed after 2012 to claim the Federal Production Tax Credit (PTC), a 2 cent per kilowatt-hour tax incentive that is set to expire on December 31, 2012. Wind plants are assumed to depreciate capital expenses using the Modified Accelerated Cost Recovery Schedule with a 5-year tax life.

Offshore wind resources are represented as a separate technology from onshore wind resources. Offshore resources are modeled with a similar model structure as onshore wind. However, because of the unique challenges of offshore construction and the somewhat different resource quality, the assumptions with regard to capital cost, learning-by-doing cost reductions, and variation of resource exploitation costs and performance differ significantly from onshore wind.

- Like onshore resources, offshore resources are assumed to have an upwardly sloping supply curve, in part influenced by the same factors that determine the onshore supply curve (such as distance to load centers, environmental or aesthetic concerns, variable terrain/seabed) but also explicitly by water depth.
- Because of the more difficult maintenance challenge offshore, performance for given annual average wind power density level is assumed to be somewhat reduced by reduced turbine availability. Offsetting this, however, is the availability of resource areas with higher overall power density than is assumed available onshore. Capacity factors for offshore are limited to be about 50 percent for a Class 7 site.
- Cost reductions in the offshore technology result in part from learning reductions in onshore wind technology as well as from cost reductions unique to offshore installations, such as foundation design and construction techniques. Because offshore technology is significantly less mature than onshore wind technology, offshore-specific technology learning occurs at a somewhat faster rate than on-shore technology. A technological optimism factor (see emm documentation: http://www.eia.gov/FTPROOT/modeldoc/m068(2010).pdf) is included for offshore wind to account for the substantial cost of establishing the unique construction infrastructure required for this technology.

Geothermal-Electric Power Submodule

Background

Beginning in *AEO2011*, all geothermal supply curve data came from the National Renewable Energy Laboratory's updated U.S. geothermal supply curve assessment. The report, released in February Of 2010, assigns cost estimates to the U.S. Geological Survey's 2008 geothermal resource assessment. Some data from the 2006 MIT report, *Future of Geothermal Energy*, was also incorporated into the NREL report, however this would be more relevant to deep, dry, and unknown geothermal resources, something which EIA did not include in its supply curve. NREL took the USGS data and used the GETEM model, described asn an Excel-based techno-economic systems analysis tool, to estimate the costs [3]. Only resources with temperatures above 110 degrees Celsius were considered. There are approximately 125 of these known, hydrothermal resources which EIA used in its supply curve. Each of these sites also has what NREL classified as "near-field enhanced geothermal energy system potential" which are in areas around the indentified site that lack the permeability of fluids that are present in the hydrothermal potential. Therefore, there are 250 total points on the supply curve since each of the 125 hydrothermal sites has corresponding EGS potential.

In the past, EIA cost estimates were broken down into cost-specific components. Unfortunately, this level of detal was not available in the NERL data. A site-specific capital cost and fixed operations and maintenance cost was provided. Both types of technology, both flash and binary, are also included with capacity factors ranging from 90 to 95 percent. While the sourve of the data has changed from previous years, the site-by-site matrix input that acts as the supply curve has been retained.

Assumptions

- Existing and identified planned capacity data are obtained directly by the EMM from Forms EIA-860A(utilities) and EIA-860B (nonutilities) and from supplemental additions (See Below).
- The permanent investment tax credit of 10 percent available in all projection years based on the EPACT applies to all geothermal capital costs, except through December 2013 when the 2-cent production tax credit is available to this technology and is assumed chosen instead.
- Plants are not assumed to retire unless their retirement is reported to EIA. Geysers units are not assumed to retire but instead are assigned the 35 percent capacity factors reported to EIA reflecting their reduced performance in recent years.
- Capital and operating costs vary by site and year; values shown in Table 8.3 in the EMM chapter are indicative of those used by EMM for geothermal build and dispatch decisions

Biomass Electric Power Submodule

Background

Biomass consumed for electricity generation is modeled in two parts in NEMS. Capacity in the wood products and paper industries, the so-called captive capacity, is included in the industrial sector module as cogeneration. Generation by the electricity sector is represented in the EMM, with capital and operating costs and capacity factors as shown in Table 8.2 in the EMM chapter, as well as fuel costs, being passed to the EMM where it competes with other sources. Fuel costs are provided in sets of regional supply schedules. Projections for ethanol are produced by the Petroleum Market Module (PMM), with the quantities of biomass consumed for ethanol decremented from, and prices obtained from, the EMM regional supply schedules.

Assumptions

- Existing and planned capacity data are obtained from Form EIA-860.
- The conversion technology represented, upon which the costs in Table 8.3 in the EMM chapter are based, is an advanced gasification-combined cycle plant that is similar to a coal-fired gasifier. Costs in the Reference case were developed by EIA to be consistent with coal gasifier costs. Short-term cost adjustment factors are used.
- Biomass cofiring can occur up to a maximum of 15 percent of fuel used in coal-fired generating plants.

Fuel supply schedules are a composite of four fuel types: forestry materials, wood residues, agricultural residues and energy crops. All feedstock cost and quantity data are based off of forestry inventories and POLYSYS runs completed by Oak Ridge National Laboratory. Energy crop data are presented in yearly schedules from 2010 to 2035 in combination with the other material types for each region. The forestry materials component is made up of logging residues, rough rotten salvageable dead wood, and excess small pole trees [4]. The wood residue component consists of primary mill residues, silvicultural trimmings, and urban wood such as pallets, construction waste, and demolition debris that are not otherwise used [5]. Agricultural residues are wheat straw, corn stover, and a number of other major agricultural crops [6]. Energy crop data are for hybrid poplar, willow, and switchgrass grown on crop land, pasture land, or on Conservation Reserve Program lands. In *AEO2009*, agricultural residues and energy crops are combined into a single “agricultural sector” [7]. The maximum amount of resources in each supply category is shown in Table 13.2.

Table 13.2. 2020 Maximum U.S. biomass resources, by coal demand region and type
trillion Btu

Coal Demand Region	States	Agricultural Sector	Forestry Residue	Urban Wood Waste/Mill Residue	Total[1]
1	CT, MA, ME, NH, RI, VT	165	158	15	339
2	NY, PA, NJ	277	167	59	503
3	WV, MD, DC, DE, VA, NC, SC	436	426	56	918
4	GA, FL	239	265	47	551
5	OH	348	37	16	402
6	IN, IL, MI, WI	1209	190	47	1,446
7	KY, TN	497	152	30	679
8	AL, MS	357	326	19	702
9	MN, IA, ND, SD, NE, MO, KS	2294	155	28	2,477
10	TX, LA, OK, AR	728	378	57	1,163
11	MT, WY, ID	197	100	25	322
12	CO, UT, NV	209	70	7	285
13	AZ, NM	168	45	7	220
14	AK, HI, WA, OR, CA	226	429	83	738

[1]May include error

Sources: Urban Wood Wastes: Antares Group Inc., Biomass Residue Supply Curves for the U.S (updated), prepared for the National Renewable Energy Laboratory, June 1999; Agricultural residues, energy crops, and forestry residues from the University of Tennessee Department of Agricultural Economics POLYSIS model, May 2008.

Landfill-Gas-to-Electricity Submodule

Background

Landfill-gas-to-electricity capacity competes with other technologies using supply curves that are based on the amount of "high", "low", and "very low" methane producing landfills located in each EMM region. An average cost-of-electricity for each type of landfill is calculated using gas collection system and electricity generator costs and characteristics developed by EPA's "Energy Project Landfill Gas Utilization Software" (E-PLUS) [8] .

Assumptions

- Gross domestic product (GDP) and population are used as the drivers in an econometric equation that establishes the supply of landfill gas.
- Recycling is assumed to account for 35 percent of the total waste stream by 2005 and 50 percent by 2010 (consistent with EPA's recycling goals).
- The waste stream is characterized into three categories: readily, moderately, and slowly decomposable material.
- Emission parameters are the same as those used in calculating historical methane emissions in the EIA's Emissions of Greenhouse Gases in the United States 2003 [9] .
- The ratio of "high", "low", and "very low" methane production sites to total methane production is calculated from data obtained for 156 operating landfills contained in the Government Advisory Associates METH2000 database [10] .
- Cost-of-electricity for each site was calculated by assuming each site to be a 100-acre by 50-foot deep landfill and by applying methane emission factors for "high", "low", and "very low" methane emitting wastes.

Conventional hydroelectricity

The conventional hydroelectricity submodule represents U.S. potential for new conventional hydroelectric capacity 1 megawatt or greater from new dams, existing dams without hydroelectricity, and from adding capacity at existing hydroelectric dams. Summary hydroelectric potential is derived from reported lists of potential new sites assembled from Federal Energy Regulatory Commission (FERC) license applications and other survey information, plus estimates of capital and other costs prepared by the Idaho National Engineering and Environmental Laboratory (INEEL) [11]. Annual performance estimates (capacity factors) were taken from the generally lower but site specific FERC estimates rather than from the general estimates prepared by INEEL, and only sites with estimated costs 10 cents per kilowatthour or lower are included in the supply. Pumped storage hydro, considered a nonrenewable storage medium for fossil and nuclear power, is not included in the supply; moreover, the supply does not consider offshore or in-stream hydro, efficiency or operational improvements without capital additions, or additional potential from refurbishing existing hydroelectric capacity.

In the hydroelectricity submodule, sites are first arrayed by NEMS region from least to highest cost per kilowatthour. For any year's capacity decisions, only those hydroelectric sites whose estimated levelized costs per kilowatthour are equal to or less than an EMM determined avoided cost (the least cost of other technology choices determined in the previous decision cycle) are submitted. Next, the array of below-avoided cost sites is parceled into three increasing cost groups, with each group characterized by the average capacity-weighted cost and performance of its component sites. Finally, the EMM receives from the conventional hydroelectricity submodule the three increasing-cost quantities of potential capacity for each region, providing the number of megawatts potential along with their capacity-weighted average overnight capital cost, operations and maintenance cost, and average capacity factor. After choosing from the supply, the EMM informs the hydroelectricity submodule, which decrements available regional potential in preparation for the next capacity decision cycle.

Legislation and regulations

Renewable electricity tax credits

The RFM includes the investment and energy production tax credits codified in the Energy Policy Act of 1992 (EPACT 92) as amended. The investment tax credit established by EPACT 92 provides a credit to Federal income tax liability worth 10 percent of initial investment cost for a solar, geothermal, or qualifying biomass facility. This credit was raised to 30 percent through 2016 for some solar projects and extended to residential projects. This change is reflected in the utility, commercial and residential modules. The production tax credit, as established by EPACT 92, applied to wind and certain biomass facilities. As amended, it provides a 2.1 cent tax credit for every kilowatt-hour of electricity produced for the first 10 years of operation for a wind facility constructed by December 31, 2012 or by December 31, 2013 for other eligible facilities. The value of the credit, originally 1.5 cents, is adjusted annually for inflation. With the various amendments, the production tax credit is available for electricity produced from qualifying geothermal, animal waste, certain small-scale hydroelectric, landfill gas, municipal solid waste, and additional biomass resources. Wind, poultry litter and geothermal, and "closed loop" [12] biomass resources receive a 2.1 cent tax credit for the first 10 years of facility operations. All other renewable resources receive a 1 cent (that is, one-half the vale of the credit for other resources) tax credit for the first 10 years of facility operations. EIA assumes that biiomass facilities obtaining the PTC will use "open-loop" fuels, as "closed-loop" fuels are assumed to be unavailable and/or too expensive for widespread use during the period that the tax credit is available. The investment and production tax credits are exclusive of one another, and may not both be claimed for the same geothermal facility (which is eligible to receive either).

State RPS programs

EIA represents various state-level policies generally referred to as Renewable Portfolio Standards (RPS). These policies vary significantly among states, but typically require the addition of renewable generation to meet a specified share of state-wide generation. Any non-discretionary limitations on meeting the generation or capacity target are modeled to the extent possible. However, because of the complexity of the various requirements, the regional target aggregation (described below), and nature of some of the limitations (also described below), measurement of compliance is assumed to be approximate.

Regional renewable generation targets were estimated using the renewable generation targets in each state within the region. In many cases, regional boundaries intersect state boundaries; in these cases state requirements were divided among relevant regions based on sales. Using state-level RPS compliance schedules and preliminary estimates of projected sales growth, EIA estimated the amount of renewable generation required in each state within a region. Required generation in each state was then summed to the regional level for each year, and a regional renewable generation share of total sales was determined, as shown in Table 13.3.

Only targets with established enforcement provisions or established state funding mechanisms were included in the calculation; goals, provisional RPS requirements, or requirements lacking established funding were not included. The California and New York programs require state funding, and these programs are assumed to be complied with only to the extent that state funding allows. Compliance enforcement provisions vary significantly among states and most states have established procedures for waiving compliance through the use of "alternative compliance" payments, penalty payments, discretionary regulatory waivers, or retail price impact limits. Because of the variety of mechanisms, even within a given electricity market region, these limits are not modeled.

Alternative renewable cases

Renewable Technology cases

Two cases examine the effect on energy supply using alternative assumptions for cost and performance of non-hyrdo, non-landfill gas renewable energy technologies. The High Renewable Cost case examines the effect if technology costs were to remain at current levels. The Low Renewable Cost case examines the effect if technology energy costs were reduced by 2035 to 40 percent below Reference case values with an initial reduction of 20%.

The High Renewable Cost case does not allow "learning-by-doing" effects to reduce the capital cost of biomass, geothermal, solar, or wind technologies or to improve wind capacity factor beyond 2011 levels. The construction of the first four units of biomass integrated gasification combined cycle units are still assumed to reduce the technological optimism factor associated with this technology. Although the cost of biomass fuels is assumed to remain the same in this case as in the Reference case, this case assumes that no energy crops will be available through 2035, consistent with the "frozen technology" assumptions for the other technologies. All other parameters remain the same as in the Reference case.

Table 13.3. Aggregate regional RPS requirements

Region[1]	2015	2025	2035
ERCT	4.20%	4.20%	4.20%
MORE	10.00%	10.00%	10.00%
MROW	4.90%	7.30%	7.30%
NEWE	22.70%	13.80%	13.80%
NYCW	25.70%	25.70%	25.70%
NYLI	25.70%	25.70%	25.70%
NYUP	25.70%	25.70%	25.70%
RFCE	9.50%	14.40%	14.50%
RFCM	10.00%	10.00%	10.00%
RFCW	4.30%	9.60%	9.60%
SRDA	0.60%	0.70%	0.70%
SRGW	6.60%	15.70%	15.70%
SRVC	2.60%	5.20%	5.20%
SPNO	7.00%	15.20%	15.30%
SPSO	1.30%	1.60%	1.60%
AZNM	6.30%	10.00%	10.00%
CAMX	22.50%	33.00%	33.00%
NWPP	5.10%	11.40%	11.40%
RMPA	9.90%	14.80%	18.50%

[1] See chapter on the Electricity Market Module for a map of the electricity regions.

The Low Renewable Cost case assumes that the non-hydro, non-landfill gas renewable technologies are able to reduce their cost in 2035 by 40 percent from the Reference case.

Because the cost of supply of renewable resources is assumed to increase with increasing utilization (that is, the renewable resource supply curves are upwardly sloping), the cost reduction is achieved by targeting the reduction on the "marginal" unit of supply for each technology in 2035 for the Reference case (that is, the next resource available to be utilized in the Reference case in 2035). This has the effect of reducing costs for the entire supply (that is, shifting the supply curve downward by 40 percent). As a result of the overall reduction in costs, more supply may be utilized, and a unit from higher on the supply curve may result in being the marginal unit of supply. Thus the actual market-clearing cost-of-energy for a given renewable technology may not differ by much from the Reference case, although that resource contributes more energy supply than in the Reference case. These cost reductions are achieved gradually and are only fully realized by 2035.

For wind, biomass, geothermal, and solar technologies, this cost reduction is achieved by a reduction in overnight capital costs sufficient to achieve the targeted reduction in cost-of-energy. For geothermal, the capital cost of the lowest-cost site available in the year 2010 is reduced such that if it were available for construction in 2035, it would have a 40 percent lower cost-of-energy in the High Renewable case than the cost-of-energy it would have in 2035 were it available for construction in the Reference case. Biomass prices is assumed to be reduced 40 percent by 2035 for a given quantity of fuel supplied. Other assumptions within NEMS are unchanged from the Reference case.

For the Low Renewable Cost case, demand-side improvements are also assumed in the renewable energy technology options of residential and commercial buildings, industrial processes, and refinery fuels modules. Details on these assumptions can be found in the corresponding sections of this report.

Notes and sources

[1] For a comprehensive description of each submodule, see Energy Information Administration, Office of Integrated Analysis and Forecasting, Model Documentation, Renewable Fuels Module of the National Energy Modeling System, DOE/EIA-M069(2010), (Washington, DC, March 2010).

[2] Revising the Long Term Multipliers in NEMS: Quantifying the Incremental Transmission Costs Due to Wind Power, Report to EIA from Princeton Energy Resources International, LLC. May 2007.

[3] The one exception applies to the Salton Sea resource area. For that site, EIA used cost estimates provided by RW Beck rather than NREL.

[4] United States Department of Agriculture, U.S. Forest Service, "Forest Resources of the United States, 1992", General Technical Report RM-234, (Fort Collins CO, June 1994).

[5] Antares Group Inc., "Biomass Residue Supply Curves for the U.S (updated)", prepared for the National Renewable Energy Laboratory, June 1999.

[6] Walsh, M.E., et.al., Oak Ridge National Laboratory, "The Economic Impacts of Bioenergy Crop Production on U.S. Agriculture", (Oak Ridge, TN, May 2000), http://bioenergy.ornl.gov/papers/wagin/index.html.

[7] Graham, R.L., et.al., Oak Ridge National Laboratory, "The Oak Ridge Energy Crop County Level Database", (Oak Ridge TN, December, 1996).

[8] U.S. Environmental Protection Agency, Atmospheric Pollution Prevention Division, Energy Project Landfill Gas Utilization Software (E-PLUS) Version 1.0, EPA-430-B-97-006 (Washington, DC, January 1997).

[9] Energy Information Administration, "Emissions of Greenhouse Gases in the United States 2003", DOE/EIA-0573(2003) (Washington, DC, December 2004).

[10] Governmental Advisory Associates, Inc., METH2000 Database, Westport, CT, January 25, 2000.

[11] Douglas G. Hall, Richard T. Hunt, Kelly S. Reeves, and Greg R. Carroll, Idaho National Engineering and Environmental Laboratory, "Estimation of Economic Parameters of U.S. Hydropower Resources" INEEL/EXT-03-00662 (Idaho Falls, Idaho, June 2003).

[12] Closed-loop biomass are crops produced explicitly for energy production. Open-loop biomass are generally wastes or residues that are a byproduct of some other process, such as crops grown for food, forestry, landscaping, or wood milling.

Appendix A: Handling of Federal and selected State legislation and regulation in the AEO

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Legislation	Brief description	AEO handling	Basis
Residential sector			
A. National Appliance Energy Conservation Act of 1987	Requires Secretary of Energy to set minimum efficiency standards for 10 appliance categories with periodic updates	Included for categories represented in the AEO residential sector forecast.	EPACT05.
a. Room air conditioners	Sets standards for room air conditioners in 2000.	Require new purchases of room air conditioners to meet the standard.	Federal Register Notice of Final Rulemaking.
b. Other air conditioners (<5.4 tons)	Sets standards for other air conditioners in 2006.	Require new purchases of other air conditioners to meet the standard.	Federal Register Notice of Final Rulemaking.
c. Water heaters	Sets standards for water heaters in 2015.	Require new purchases of water heaters to meet the standard.	Federal Register Notice of Final Rulemaking.
d. Refrigerators/freezers kWh/yr	Sets standards for refrigerators/freezers in 2001.	Require new purchases of refrigerators/freezers to meet the standard.	Federal Register Notice of Final Rulemaking.
e. Dishwashers	Sets standards for dishwasher in 2010.	Require new purchases of dishwashers to meet the standard.	Federal Register Notice of Final Rulemaking.
f. Fluorescent lamp ballasts	Sets standards for fluorescent lamp ballasts in 2005.	Require new purchases of fluorescent lamp ballasts to meet the standard.	Federal Register Notice of Final Rulemaking.
g. Clothes washers	Sets standards for clothes washers in 2011.	Require new purchases of clothes washers to meet the standard.	Federal Register Notice of Final Rulemaking.
h. Furnaces	Sets standards for furnaces in 2015.	Require new purchases of furnaces to meet the standard.	Federal Register Notice of Final Rulemaking.
i. Clothes dryers	Sets standards for clothes dryers in 1994.	Require new purchases of clothes dryers to meet the standard.	Federal Register Notice of Final Rulemaking.
B. Energy Policy Act of 1982 (EPACT92)			
a. Building codes	For the IECC 2006, specifies whole house efficiency minimums.	Assumes that all States adopt the IECC 2006 code by 2017.	Trend of States adoption to codes, allowing for lead times for enforcement and builder compliance.
b. Energy-efficient mortgages	Allow homeowners to qualify for higher loan amounts if the home is energy-efficient, as scored by the Home Energy Rating System (HERS).	Efficiency of equipment represented in technology choice parameters. Efficiency of shell represented in HVAC choice.	Trend of States adoption to codes, allowing for lead times for enforcement and builder compliance.
C. Energy Policy Act of 2005 (EPACT05)			
a. Touchiere lamp standard		Sets 190 watt bulb limit in 2006.	EPACT05.
b. Ceiling fan light kit standard	Ceiling fans must be shipped with compact fluroescent bulbs or use no more than 190 watts per fixture in 2007.	Reduce lighting electricity consumption by appropriate amount.	Number of ceiling fan shipments and estimated kWh savings per unit determine overall savings.

	Legislation	Brief description	AEO handling	Basis
	c. Dehumidifier standard	Sets standard for dehumidifiers in 2007 and 2012.	Reduce miscellaneous electricity consumption by appropriate amount.	Number of dehumidifier shipments and estimated kWh savings per unit determine overall savings.
	d. Energy-efficient equipment tax credit	Purchasers of certain energy efficient equipment can claim tax credits in 2006 and 2007.	Reduce cost of applicable equipment by specified amount.	
	e. New home tax credit	Builders receive $1000 or $2000 tax credit if they build homes 30 or 50 percent better than code in 2006 and 2007.	Reduce shell package cost for these homes by specified amount.	Cost reductions to consumers are assumed to be 100 percent of the builder's tax credit.
	f. Energy-efficient appliance tax credit	Producers of energy-efficient refrigerators, dishwashers, and clothes washers receive tax credits for each unit they produce that meets certain efficiency specifications	Assume the cost savings are passed on to the consumer, reducing the price of the appliance by the specified amount.	Cost reductions to consumers are assumed to be 100 percent of the producer's tax credit.
D.	Energy Independence and Security Act of 2007 (EISA 2007)			
	a. General service incandescent lamp standard	Require less wattage for bulbs in 2012-2014 and 2020.	Reduce wattage for new bulbs by 28 percent in 2013 and 67 percent in 2020.	EISA 2007.
	b. Dehumidifier standard	Updates EPACT 2005 standard.	Reduce miscellaneous electricity consumption by appropriate amount.	Increase savings estimated for EPACT 2005 by appropriate amount.
	c. Boiler standard	Sets standards for boilers in 2013.	Require new purchases of boilers to meet the standard.	EISA 2007.
	d. Dishwasher standard	Sets standards for dishwashers in 2010.	Require new purchases of dishwashers to meet the standard by 2010.	EISA 2007.
	e. External power supply standard	Sets standards for external power supplies in 2008	Reduce miscellaneous electricity consumption by appropriate amount.	Number of shipments and estimated kWh savings per unit determin e overa ll savings.
	f. Manufactured housing code	Require manufactured homes to meet latest IECC in 2011.	Require that all manufactured homes shipped after 2011 meet the IECC 2006	EISA 2007.
E.	Energy Improvement and Extension Act of 2008 (EIEA 2008)			
	a. Energy-efficient equipment tax credit	Purchasers of certain energy efficient equipment can claim tax credits through 2016.	Reduce the cost of applicable equipment by specified amount.	EIEA 2008.
	b. Energy-efficient appliance tax credit	Producers of energy-efficient refrigerators, clothes washers, and dishwashers receive tax credits for each unit they produce that meets certain efficiency specifications, subject to an annual cap.	Assume the cost savings are passed on to the consumer, reducing the price of the appliance by the specified amount.	Cost reductions to consumer are assumed to be 100% of the producer's tax credit.

	Legislation	Brief description	AEO handling	Basis
F.	American Recovery and Reinvestment Act of 2009			
	a. Energy-efficient equipment tax credit	Increases cap to $1500 of energy efficient equipment specified under Section C(d) above. Removes cap for PV, wind, and ground-source heat pumps	Reduce the cost of applicable equipment by specified amount.	EPACT 2005 and ARRA 2009.
	b. Weatherization and state energy programs	Increases funding for weatherization and other programs to increase the energy efficiency of existing housing stock.	Apply annual funding amount to existing housin g retrofits. Savings for heating and cooling based on $2600 per home investment as specified in weatherization program evaluation.	ARRA 2009.
	Commercial sector			
A.	National Appliance Energy Conservation Act of 1987	Requires Secretary of Energy to set minimum efficiency standards for 10 appliance categories.	Included for categories represented in the AEO commercial sector forecast.	
	a. Room air conditioners		Current standard of 9.8 EER.	Federal Register Notice of Final Rulemaking.
	b. Other residential-size air conditioners (<5.4 tons)		Curent standard 10 SEER for central air conditioning and heat pumps, increasing to 13 SEER in 2006	Federal Register Notice of Final Rulemaking.
	c. Fluorescent lamp ballasts		Current standard if .90 power factor and minimum efficacy factor for F40 and F96 lamps based on lamp size and wattage, increasing to higher efficacy factor in 2005 that limits purchases to electronic ballasts.	Federal Register Notice of Final Rulemaking.
B.	Energy Policy Act of 1992 (EPACT92)			
	a. Buildings codes		Incorporated in commercial building shell assumptions. Efficiency of new relative to existing shell represented in shell efficiency indices. Assumes shell efficiency improves 5 and 7 percent by 2030 for existing buildings and new construction, respectively.	Based on Science Applications International Corporation commercial shell indices for 2003 developed for EIA in 2008.
	b. Window labeling	Designed to help consumers determine which windows are more energy efficient.	Incorporated in commercial building shell assumptions. Efficiency of new relative to existing shell represented by shell efficiency indices. Assume shell efficiency improves 5 and 7 percent by 2030 for existing buildings and new construction, respectively.	Based on Science Applications International Corporation commercial shell indices for 2003 developed for EIA in 2008.
	c. Commercial furnaces and boilers		Gas-fired furnaces and boilers: Current standard is 0.80 thermal efficiency. Oil furnaces and boilers: Current standard is 0.81 thermal efficiency for furnaces, 0.83 thermal efficiency for boilers.	Public Law 102-486: EPACT92. Federal Register Notice of Final Rulemaking.

	Legislation	Brief description	AEO handling	Basis
	d. Commercial air conditioners and heat pumps		Air-cooled air conditioners and heat pumps less than 135,000 Btu: Current standard of 8.9 EER. Air-cooled air conditioners and heat pumps greater than 135,000 Btu: Current standard of 8.5 EER.	Public Law 102-486: EPACT92.
	e. Commercial water heaters		Natural gas and oil: EPACT standard .78 thermal efficiency increasing to .80 thermal efficiency for gas units in 2003.	Public Law 102-486: EPACT92. Federal Register Notice of Final Rulemakiing.
	f. Lamps		Incandescent: Current standard 16.9 lumens per watt. Fluorescent: Current standard 75 and 80 lumens per watt for 4 and 8 foot lamps, respectively.	
	g. Electric motors	Specifies minimum efficiency levels for a variety of motor types and sizes.	End-use services modeled at the equipment level. Motors contained in new equipment must meet the standards.	Public Law 102-486: EPACT92.
	h. Federal energy management	Requires Federal agencies to reduce energy consumption 20 percent by 2000 relative to 1995.	Superseded by Executive Order 13123, EPACT05, and EISA07.	Superseded by Executive Order 13123.
	i. Business investment energy credit	Provides a permanent 10 percent investment tax credit for solar property.	Tax credit incorporated in cash flow for solar generation systems. Investment cost reduced 10 percent for solar water heaters.	Public Law 102-486: EPACT92
C.	Executive Order 13123. Greening the Government Through Efficient Energy Management	Requires Federal agencies to reduce energy consumption 30 percent by 2005 and 35 percent by 2010 relative to 1985 through life-cycle cost-effective energy measures.	Superseded by EPACT05 and EISA07.	Superseded by EPACT05 and EISA07.
D.	Energy Policy Act of 2005 (EPACT05)			
	a. Commercial package air conditioners and heat pumps	Sets minimum efficiency levels in 2010.	Air-cooled air conditioners/heat pumps less than 135,000 Btu: standard of 11.2/11.0 EER and heating COP of 3.3. Air-cooled air conditioners/heat pumps greater than 135,000 Btu: standard of 11.0/10.6 EER and heating COP of 3.2.	Public Law 109-58: EPACT05.
	b. Commercial refrigerators, freezers, and automatic icemakers	Sets minium efficiency levels in 2010.	Set standard by level of improvement above stock average efficiency in 2003.	Public Law 190-58: EPACT05.
	c. Lamp ballasts	Bans manufacture or import of mercury vapor lamp ballasts in 2008. Sets minimum efficacy level for T12 energy saver ballasts in 2009 and 2010 based on application.	Remove mercury vapor lighting system from technology choice menu in 2008. Set minimum efficacy of T12 ballasts at specified standard levels.	Public Law 102-58: EPACT05.
	d. Compact fluorescent lamps	Sets standard for medium base lamps at Energy Star requirements in 2006.	Set efficacy level of compact fluorescent lamps at required level.	Public Law 109-58: EPACT05.

Legislation	Brief description	AEO handling	Basis
e. Illuminated exit signs and traffic signals	Set standards at Energy Star requirements in 2006.	Reduce miscellaneous electricity consumption by appropriate amount.	Number of shipments, share of shipments that currently meet standard, and estimated kWh savings per unit determine overall savings.
f. Distribution transformers	Sets standard as National Electricial Manufacturers Association Class I Efficiency levels in 2007.	Effects of the standard are included in estimating the share of miscellaneous electricity consumption attributable to transformer losses.	Public Law 109-58: EPACT05.
g. Prerinse spray valves	Sets maximum flow rate to 1.6 gallons per minute in 2006.	Reduce energy use for water heating by appropriate amount.	Number of shipments, share of shipments that currently meet standard, and estimated kWh savings per unit determine overall savings.
h. Federal energy management	Requires Federal agencies to reduce energy consumption 20 percent by 2015 relative to 2003 through life-cycle cost-effective energy measures.	The Federal "share" of the commercial sector uses the 10 year Treasury note rate as a discount rate in equipment purchase decisions as opposed to adding risk premiums to the 10 year Treasury note rate to develop discount rates for other commercial decisions	Public law 109-58: EPACT05. Superseded by EISA07.
i. Business investment tax credit for fuel cells and microturbines	Provides a 30 percent investment tax credit for fuel cells and a 10 percent investment tax credit for microturbines installed in 2006 through 2008.	Tax credit incorporated in cash flow for fuel cells and microturbines.	Public Law 109-58: EPACT05. Extended through 2008 by Public Law 109-432. Extended through 2016 by EIEA08.
j. Business solar investment tax credit	Provides a 30 percent investment tax credit for solar property installed in 2006 through 2008.	Tax credit incorporated in cash flow for solar generation systems. Investment cost reduced 30 percent for solar water heaters.	Public Law 109-58: EPACT05. Extended through 2008 by Public Law 109-432. Extended through 2016 by EIEA08.
E. Energy Independence and Security Act of 2007 (EISA07)			
a. Commercial walk-in coolers and walk-in freezers	Requires use of specific energy efficiency measures in equipment manufactured in or after 2009.	Set standard by equivalent level of improvement above stock average efficiency in 2003.	Public Law 110-140: EISA07.
b. Incandescent and halogen lamps	Sets maximum allowable wattage based on lumen output starting in 2012.	Remove incandescent and halogen general service lighting systems that do not meet standard from technology choice menu in 2012.	Public Law 110-140: EISA07.
c. Metal halide lamp ballasts	Sets minimum efficiency levels for metal halide lamp ballasts starting in 2009.	Remove metal halide lighting systems that do not meet standard from technology choice menu in 2009. Set minimum system efficiency to include specified standard levels for ballasts - ranging from 88 to 94 percent based on ballast type.	Public Law 110-140: EISA07.
d. Federal use of energy efficient lighting	Requires use of energy efficient lighting fixtures and bulbs in Federal buildings to the maximum extent possible starting in 2009.	Increase proportion of sector using 10 year treasury note rate for lighting purchase decisions to represent all existing and new Federal floorspace in 2009.	Public Law 110-140: EISA07

	Legislation	Brief description	AEO handling	Basis
	e. Federal energy management	Requires Federal agencies to reduce energy consumption per square foot 30 percent by 2015 relative to 2003 through life-cycle cost-effective energy measures.	The Federal "share" of the commercial sector uses the 10 year Treasury note rate as a discount rate in equipment purchase decisions as opposed to adding risk premiums to the 10 year Treasury note rate to develop discount rates for other commercial decisions.	Public Law 110-140: EISA07.
F.	Energy Improvement and Extension Act of 2008 (EIEA08)			
	a. Business solar investment tax credit	Extends the EPACT05 30-percent investment tax credit for solar property through 2016.	Tax credit incorporated in cash flow for solar generation systems. Investment cost reduced 30 percent for solar water heaters.	Public Law 110-343: EIEA08.
	b. Business investment tax credit for fuel cells and microturbines	Extends the EPACT05 30-percent investment tax credit for fuel cells and 10-percent investment tax credit for microturbines through 2016.	Tax credit incorporated in cash flow for fuel cells and microturbines.	Public Law 110-343: EIEA08
	c. Business investment tax credit for CHP systems	Provides a 10-percent investment tax credit for CHP systems installed in 2009 through 2016	Tax credit incorporated in cash flow for CHP systems.	Public Law 110-343: EIEA08.
	d. Business investment tax credit for small wind turbines	Provides a 30-percent investment tax credit for wind turbines installed in 2009 through 2016.	Tax credit incorporated in cash flow for wind turbine generation systems.	Public Law 110-343: EIEA08.
	e. Business investment tax credit for geothermal heat pumps	Provides a 10-percent investment tax credit for geothermal heat pump systems installed in 2009 through 2016.	Investment cost for geothermal heat pump systems reduced 10 percent.	Public Law 110-343: EIEA08.
G.	American Recovery and Reinvestment Act of 2009 (ARRA09)			
	a. Business investment tax credit for small wind turbines	Removes the cap on the EIEA08 30-percent investment tax credit for wind turbines through 2016.	Tax credit incorporated in cash flow for wind turbine generation systems.	Public Law 111-5: ARRA09.
	b. Stimulus funding to Federal agencies	Provides funding for efficiency improvement in federal buildings and facilities.	Increase the proportion of sector using the 10 year Treasury note rate for purchase decisions to include all existing and new Federal floorspace in years stimulus funding is available to account for new, replacement, and retrofit projects. Assume some funding is used for solar generation, small wind turbine, and fuel cell installations.	Public Law 111-5: ARRA09.
	c. State energy program funding and energy efficiency and conservation block grants	Provides grants for state and local governments for energy efficiency and renewable energy purposes. State Energy Program funding conditioned on enactment of new building codes.	Increase the proportion of sector using the 10 year Treasury note rate for purchase decisions to include all public buildings in years stimulus funding is available. Increase new building shell efficiency to 10 percent better than 2003 by 2018 for improved building codes. Assume some funding is used for solar generation and small wind turbine systems.	Public Law 111-5: ARRA09.
	d. Funding for smart grid projects	Provides funding for smart grid demonstration projects.	Assume smart grid technologies cause consumers to become more responsive to electricity price changes by increasing the price elasticity of demand for certain end uses.	Public Law 111-5; ARRA09.

	Legislation	Brief description	AEO handling	Basis
	Industrial sector			
A.	Energy Policy Act of 1992 (EPACT92)			
	a. Motor efficiency standards	Specifies minimum efficiency levels for a variety of motor types and sizes.	New motors must meet the standards.	Standard specified in EPACT92. 10 CFR 431.
	b. Boiler efficiency standards	Specifies minimum combustion efficiency for package boilers larger than 300,000 Btu/hr. Natural Gas boilers: 80 percent, oil boilers: 83 percent.	All package boilers are assumed to meet the efficiency standards. While the standards do not apply to field-erected boilers, which are typically used in steam-intensive industries, we assume they meet the standard in the AEO.	Standard specified in EPACT92. 10 CFR 431.
B.	Clean Air Act Amendments (CCCA90)			
	a. Process emissions	Numerous process emissions requirements for specified industries and/or activities.	Not modeled because they are not directly related to energy projections.	CAAA90, 40 CFR 60.
	b. Emissions related to hazardous/ toxic substances	Numerous emissions requirements relative to hazardous and/or toxic substances.	Not modeled because they are not directly related to energy projections.	CAAA90, 40 CFR 60.
	c. Industrial SO2 emissions	Sets annual limit for industrial SO2 emissions at 5.6 million tons. If limit is reached, specific regulations could be implemented.	Industrial SO2 emissions are not projected to reach the limit (Source: EPA, National Air Pollutant Emissions Trends:1990-1998, EPA-454/R-00-002, March 2000, p. 4-3.)	CAAA90, Section 406 (42 USC 7651)
	d. Industrial boiler hazardous air pollutants	Requires industrial boilers and process heaters to meet emissions limits on HAPs to comply with the Maximum Achievable Control Technology (MACT) floor.	Not explicitly modeled because new boilers are expected to meet the standards in the absence of the rule and retrofit costs should be relatively small.	U.S. Environmental Protection Agency, National Emissions Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heatrates, 40 CFR Part 63.
	e. Emissions from stationary diesel engines	Requires engine manufacturers to meet the same emission standards as nonroad diesel engines. Fully effective in 2011.	New stationary engines meet the standards.	40 CFR Parts 60, 85, 89, 94, 1039, 1065, and 1068.
C.	Energy Policy Act of 2005 (EPACT 05)			
	a. Physical energy intensity	Voluntary commitments to reduce physical energy intensity by 2.5 percent annually for 2007-2016.	Not modeled because participation is voluntary; actual reductions will depend on future, unknown commitments.	EPACT2005, Section 106 (42 USC 15811)
	b. Mineral components of cement of concrete	Increase in mineral component of Federally procured cement or concrete.	Not modeled.	EPACT2005, Section 108 (42 USC 6966).
	c. Tax credits for coke oven	Provides a tax credit of $3.00 per barrel oil equuivalent, limited to 4000 barrels per day average. Applies to most producers of coal coke or coke gas.	Not modeled because no impact on U.S. coke plant activity is anticipated.	EPACT2005, Section 1321 (29 USC 29).

	Legislation	Brief description	AEO handling	Basis
D.	The Energy Independence and Security Act of 2007			
	a. Motor efficiency standards	Supersedes EPACT1992 Efficiency Standards no later than 2011.	Motor purchases must meet the EPAct1992 standards through 2010; afterwards purchases must meet the EISA2007 standards.	EISA2007
E.	The Energy Improvement and Extension Act of 2008			
	a. Combined heat and power tax incentive	Provides an investment tax credit for combined heat and power systems up to 50 megawatts through 2016	Costs of systems adjusted to reflect the credit.	EIEA2008, Title I, Sec. 103
	Transportation sector			
A.	Energy Policy Act of 1992 (EPACT92)	Increases the number of alternative fuel vehicles and alternative fuel use in Federal, State, and fuel provided fleets.	Assumes Federal, State and fuel provider fleets meet the mandated sales requirements.	Energy Policy Act of 1992, Public Law 102-486-Oct. 24, 1992.
B.	Low Emission Vehicle Program (LEVP)	The Clean Air Act provides California the authority to set vehicle criteria emission standards that exceed Federal standards. A part of that program mandates the sale of zero emission vehicles by manufacturers, other nonattainm ent. States are given the option of opting into the Federal or California emission standards.	Incorporates the LEVP program as amended on August 4, 2005. Assumes California, Connecticut, Maine, Massachusetts, New Jersey, New York, Rhode island, Vermont, Oregon, and Washington adopt the LEVP program as amended August 4, 2005 and that the proposed sales requirements for hybrid, electric, and fuel cell vehicles are met.	Section 177 of the Clean Air Act, 42 U.S.C. sec. 7507 (1976) and CARB, California Exhaust Emissions Standards and Test Procedures for Passenger Cars, Light-Duty Trucks, and Medium-Duty Vehicles, August 4, 2005.
C.	Corporate Average Fuel Economy (CAFE) Standard	Requires manufacturers to produce vehicles that meet a minimum Federal average fuel economy standard, promulgated jointly for model years 2012-2016 with an average greenhouse emissions standard; cars and light-trucks are regulated separately.	CAFE standards are increased for model years 2011 thorugh 2016 to meet the final CAFE rulemakings for model year 2011 and 2012 to 2016, redspectively. CAFE standards are assumed to increase from model year 2016 to 2020 to reach 35 MPG, as mandated by the Energy Independence and Security Act of 2007.	Energy Policy Conservation Act of 1975; Title 49 United States code, Chapter 329; Energy Independence and Security Act of 2007, Title 1, Section 102; Average Fuel Economy Standards Passenger Cars and Light Trucks Model Year 2011; Federal Register, Vol. 74, No. 59, March 2009; Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards, Final Rule, Federal Register, Vol. 75, No. 88, May 2010.
D.	Electric, Hybrid, and Alternative Fuel Vehicle Tax Incentives	Federal tax incentives are provided to encourage the purchase of electric, hybrid and or alternative fuel vehicles. For example, tax incentives for hybrid vehicles in the form of a $2,000 income tax deduction.	Incorporates the Federal tax incentives for hybrid and electric vehicles.	IRS Technical Publication 535; Business Expenses.

	Legislation	Brief description	AEO handling	Basis
E.	Plug-in Hybrid Vehicle Tax Credit	EIEA2008 grants a tax credit of $2,500 for PHEVs with at least 4KW h of battery capacity, with larger batteries earning an additional $417 per kWh up to a maximum of $7,500 for light-duty PHEVs. The credit will apply until 250,000 eligible PHEVs are sold or until 2015, whichever comes first.	Incorporates the Federal tax credits for PHEVs.	Energy Improvement and Extension Act of 2008, H.R.6049.
F.	The Working Families Tax Relief Act of 2004	The Act repeals the phase out of the credits which were allowed for qualified electric and clean fuel vehicles for property acquired in 2004 and 2005. The credit is reduced by 75 percent for vehicles acquired in 2006. This will provide an incentive to purchase electric and clean fuel vehicles.	The federal tax incentives are embodied in the code. This will provide an incentive to purchase electric and clean fuel vehicles but little impact is realized on projections of total highway energy use.	Sections 318 and 319 of the Working Families Tax Relief Act of 2004.
G.	State Electric, Hybrid, and Alternative Fuel Vehicle Tax and Other Incentives	Approximately 20 States provide tax and other incentives to encourage the purchase of electric, hybrid and or alternative fuel vehicles. The tax incentives are in the form of income reductions, tax credits, and exemptions. Other incentives include use of HOV lanes and exemptions from emissions inspections from emissions inspections and licensing fees. The incentives offered and the mix varies by State. For example, Georgia offers a tax credit of $5,000 for electric vehicles and Oklahoma offers a tax credit of $1,500 for hybrid and alternative fuel vehicles.	Does not incorporate State tax and other incentives for hybrid, electric, and other alternative fuel vehicle.	State laws in Arizona, Arkansas, California, Colorado, Delaware, Florida, Georgia, Iowa, Kansas, Louisiana, Maine, Maryland, Michigan, New Hampshire, New York, Oklahoma, Pennsylvania, Utah, Virginia, and Washington.
H.	Energy Policy Act of 2005	Provides tax credits for the purchase of vehicles that have a lean burn engine or employ a hybrid or fuel cell propulsion system. The amount of the credit received for a vehicle is based on the vehicle's inertia weight, improvement in city tested fuel economy relative to an equivalent 2002 base year value, emissions classification, type of propulsion system, and number of vehicles sold.	Incorporates the Federal tax incentives for hybrid and fuel cell vehicles.	Title XIII, Section 1341 of the Energy Policy Act of 2005.
	Electric power generation			
A.	Clean Air Act Amendment of 1990	Established a national limit on electricity generator emissions of sulfur dioxide to be achieved through a cap and trade program.	Sulfur dioxide cap and trade program is explicitly modeled, choosing the optimal mix of options for meeting the national emissions cap.	Clean Air Act Amendments of 1990, Title IV, Sections 401 through 406, Sulfur Dioxide Reduction Program, 42 U.S.C. 7651a through 7651e.
		Set boiler type specific nitrogen oxide emissions limits for electricity generators.	Assumes each boiler installs the options necessary to comply with their nitrogen oxide emissions limit.	Clean Air Act Amendments of 1990, Title IV, Sections 407, Nitrogen Oxide Emission Reduction Program, 42 U.S.C. 7651f.
		Under section 126, Northeast States petitioned the EPA arguing that generators in other States contributed to the nitrogen oxide emissions problems in	The 19-State summer season nitrogen oxide cap and trade program is explicitly modeled, allowing	Section 126 Rule: Revised Deadlines, Federal Register: April 30, 2002 (volume 67,

	Legislation	Brief description	AEO handling	Basis
		their States. EPA established a summer season nitrogen oxide emission capand trade program covering 22 States (three were removed by the courts) to start in May 2003 (delayed until May 2004).	electricity generators to choose the optimal mix of control options to meet the emission cap.	Number 83). Rules and Regulations, Pages 21521-21530.
		Requires the EPA to establish national ambient air quality standards (NAAQS). In 1997, EPA set new standards for ground level ozone and fine particulates. EPA is currently determining which areas of the ountry are not in compliance with the new standards. Area designations will be made in December 2004. States will then have until December 2007 to submit their compliance plans, and until 2009-2014 to bring all areas into compliance.	Because State implementation plans have not been established, these revised standards are not currently represented.	Clean Air Act Amendment of 1990, Title I, Sections 108 and 109, National Ambient Air Quality Standards for Ozone, 40 CFR Part 50, Federal Register, Vol 68, No 3, January 8, 2003. National Ambient Air Quality Standards for Particulate Matter, 40 CFR Part 50, Federal Register, Vol. 62, No. 138, July 18, 1997.
B.	Clean Air Interstate Rule (CAIR)	CAIR imposes a two-phased limit on emissions of sulfur dioxide and/or nitrogen oxide from electric generators in 28 states and the District of Columbia.	Cap and trade programs for SO2 and NOx are modeled explicitly, allowing the model to choose the best method for meeting the emission caps.	Federal Register, Vol. 70, No. 91 (May 12, 2005), 40 CFR Parts 51, 72, 73, 74, 77, 78 and 96.
C.	State Mercury Provisions	Many States have adopted stringent regulations to limit mercury emissions and require the best control technologies be in operation.	Although State plans vary, a general regional requirement compatible with NEMS was used to require specific mercury emission removal rates for electric generators.	Various state laws.
D.	Energy Policy Act of 1992 (EPACT92)	Created a class of generators referred to as exempt wholesale generators (EW Gs), exempt from PUCHA as long as they sell wholesale power.	Represents the development of Exempt Wholesale Generators (EWGs) or what are now referred to as independent power producers (IPPs) in all regions.	Energy Policy Act of 1992, Title VII, Electricity, Subtitle A, Exempt Wholesale Generators.
E.	The Public Utility Holding Company Act of 1935 (PUCHA)	PUCHA is a US Federal statue which was enacted to legislate against abusive practices in the utility industry. The act grants power to the US Securities and Exchange Commission (SEC) to oversee and outlaw large holding companies which might otherwise control the provision of electrical service to large regions of the country. It gives the SEC power to approve or deny mergers and acquisitions and, if necessary, force utility companies to dispose of assets or change business practices if the company's structure of activities are not deemed to be in the public interest	It is assumed that holding companies act competitively and do not use their regulated power businesses to cross-subsidize their unregulated businesses.	Public Utility Holding Company Act of 1936.

	Legislation	Brief description	AEO handling	Basis
F.	FERC Orders 888 and 889	FERC has issued two related rules-Orders 888 and 889 designed to bring low cost power to consumers through competition, ensure continued reliability in the industry, and provide for open and equitable transmission services by owners of these facilities. Specifically, Order 888 requires open access to the transmission grid currently owned and operated by utilities. The transmission owners must file nondiscriminatory tariffs that offer other suppliers the same services that the owners provide for themselves. Order 888 also allows these utilities to recover stranded costs (investments in generating assets that are unrecoverable due to consumers selecting another supplier). Order 889 requires utilities to implement standards of conduct and a Open Access Same-time Information System (OASIS) through which utilities and non-utilities can receive information regarding the transmission system. Consequently, utilities are expected to functionally or physically unbundle their marketing functions from their transmission functions.	These orders are represented in the forecast by assuming that all generators in a given region are able to satisfy load requirements anywhere within the region. Similarly, it is assumed that transactions between regions will occur if the cost differentials between them make it economic to do so.	Promoting Wholesale Competition Through Open Access, Non-Discriminatory Transmission Services by Public Utilities; Public Utilities and Transmitting Utilities, ORDER NO. 888 (Issued April 24, 1996), 18 CFR Parts 35 and 385, Docket Nos. RM95-8-000 and RM94-7-001. Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct, ORDER NO. 889, (Issued April 24, 1996), 18 CFR Part 37, Docket No. RM95-9-000.
G.	New Source Review (NSR)	On August 28, 2003, the EPA issued a final rule defining certain power plant and industrial facility activities as routine maintenance, repair and replacement, which are not subject to new source review (NSR). As stated by EPA, these changes provide a category of equipment replacement activities that are not subject to Major NSR requirements under the routine maintenance, repair and replacement (RMRR) exclusion.[1] Essentially this means that power plants and industrial facilities engaging in RMRR activities will not have to get preconstruction approval from the State or EPA and will not have to install best available emissions control technologies that might be required if NSR were triggered.	It is assumed that coal plants will be able to increase their output as electricity demand increases. Their maximum capacity factor is set at 84 percent. No increases in the capacity of existing plants is assumed. If further analysis shows that capacity uprates may result from the NSR rule, they will be incorporated in future AEOs. However, at this time, the NSR rule is being contested in the courts.	EPA, 40 CFR Parts 51 and 52, Deterioration (PSD) and Non-Replacement Provision of the Vol. 68, No. 207, page 61248, Prevention of Significant Attainment New Source Review (NSR): Equipment Routine Maintenance, Repair and Replacement Exclusion; Final Rule, Federal Register, October 27, 2003.
H.	State RPS Laws, Mandates, and Goals	Several States have enacted laws requiring that a certain percentage of their generation come from qualifying renewable sources	The AEO reference case represents the Renewable Portfolio Standard (RPS) or substantively similar laws from 30 States and the District of Columbia. As described in the	The 30 States with RPS or other mandates providing quantified projections are detailed in the Legislation and Regulations section of this report.

	Legislation	Brief description	AEO handling	Basis
			Renewable Fuels Module chapter of this document, mandatory targets from the various States are aggregated at the regional level, and achievement of nondiscretionary compliance criteria is evaluated for each region.	
I.	State Environmental Laws	Several States have enacted laws requiring emissions reductions from their generating plants.	Where compliance plans have been announced, they have been incorporated. In total 31 gigawatts of planned SO2 scrubbers, 18 gigawatts of planned selective catalytic reduction (SCR) and 3 gigawatts of planned elective non-catalytic reduction (SNCR) are represented.	North Carolina's Clean Smoke Stacks Act, Session Law 2002-4, Senate Bill 1078, An Act to Improve Air Quality in the State by Imposing Limits on the Emission of Certain Pollutants from Certain Facilities that Burn Coal to Generate Electricity and to Provide for Recovery by Electric Utilities of the Costs of Achieving Compliance with those Limits.
J.	Energy Policy Act of 2005	Extended and substantially expanded and modified the Production Tax Credit, originally created by EPACT1992.	EPACT2005 also adds a PTC for up to 6,000 megawatts of new nuclear capacity and a $1.3 billion investment tax credit for new or repowered coal-fired power projects. The tax credits for renewables, nuclear and coal projects are explicitly modeled as specified in the law and subsequent amendments.	Energy Policy Act of 2005, Sections 1301, 1306, and 1307
K.	American Recovery and Reinvestment Act of 2009	Extends the Production Tax Credit (PTC) to wind facilities constructed by December 31, 2012 and to other eligible renewable facilities constructed by December 31, 2013. Allows PTC-eligible facilities to claim a 30 percent investment tax credit (ITC) instead of the PTC. Projects starting construction by the end of 2010 (subsequently extended to the end of 2011) may elect to take a cash grant equal to the value of the 30 percent ITC instead of either tax credit.	The extensions of the PTC and 30 percent ITC are represented in the AEO reference case as specified in the law. The AEO does not distinguish between the effects of the 30 percent ITC and the equivalent cash grant, and the cash grant is not specifically modeled.	American Recovery and Reinvestment Act of 2009, Division B, Title I, Sec. 1101, 1102, and 1603.
		ARRA provided $6 billion to pay the cost of guarantees for loans authorized by the Energy Policy Act of 2005. The purpose of these loan guarantees is to stimulate the deployment of conventional renewable and transmission technologies and innovative biofuels technologies. However, to qualify, eligible projects must be under construction by September 30, 2011.	The AEO2011 includes projects that have received loan guarantees under this authority, but does not assume automatic award of the loans to potentially eligible technologies.	American Recovery and Reinvestment Act of 2009, Title IV, "Energy and Water Development", Section 406.

	Legislation	Brief description	AEO handling	Basis
		ARRA provides $4.5 billion for smart grid demonstration projects. These generally include a wide array of measurement, communications, and control equipment employed through-out the transmission and distribution system that will enable real-time monitoring of the production, flow, and use of power from generator to consumer.	In the electricity module, it was assumed that line losses would fall slightly, peak loads would fall as customers shifted their usage patterns, and custom ers would be more responsive to pricing signals.	American Recovery and Reinvestment Act of 2009, Title IV, "Energy and Water Development", Section 405.
		ARRA provides $800 million to fund projects under the Clean Coal Power Initiative program focusing on capture and sequestration of greenhouse gases.	It was assumed that one gigawatt of new coal with sequestration capacity would come online by 2017.	American Recovery and Reinvestment Act of 2009, Title IV, "Energy and Water Development"
	Oil and gas supply			
A.	The Outer Continental Shelf Deep Water Royalty Relief Act (DWRRA)	Mandates that all tracts offered by November 22, 2000, in deep water in certain areas of the Gulf of Mexico must be offered under the new bidding system permitted by the DWRRA. The Secretary of Interior must offer such tracts with a specific minimum royalty suspension volume based on water depth.	Incorporates royalty rates based on water depth.	43 U.S.C. SS 1331-1356 (2002).
B.	Energy Policy and Conservation Act Amendments of 2000	Required the USGS to inventory oil and gas resources beneath Federal lands.	To date, the Rocky Mountain oil and gas resource inventory has been completed by the USGS. The results of this inventory have been incorporated in the technically recoverable oil and gas resource volumes used for the Rocky Mountain region.	Scientific Inventory of Onshore Federal Lands: Oil and Gas Resources and Reserves and the Extent and Nature of Restrictions or Impediments to their Development: The Paradox/San Juan, Uinta/Piceance, Greater Green River, and Powder River Basins and the Montana Thrust Belt. Prepared by the Departments of Interior, Agriculture and Energy, January 2003.
C.	Section 29 Tax Credit for Nonconventional Fuels	The Alternative Fuel Production Credit (Section 29 of the IRC) applies to qualified nonconventional fuels from wells drilled or facilities placed in service between January 1, 1980, and December 31, 1992. Gas production from qualifying wells could receive a $3 (1979 constant dollars) per barrel of oil equivalent credit on volumes produced through December 31, 2002. The qualified fuels are: oil produced from shale and tar sands; gas from geopressurized brine, Devonian shale, coal seams, tight formations, and biomass; liquid, gaseous, or solid synthetic fuels produced from coal; fuel from qualified processed formations or biomass; and steam from agricultural products.	The Section 29 Tax Credit expired on December 31, 2002, and it not considered in new production decisions. However, the effect of these credits is implicitly included in the parameters that are derived from historical data reflecting such credits.	Alternative Fuel Production Credit (Section 29 of the Internal Revenue Code), initially established in the Windfall Profit Tax of 1980.

	Legislation	Brief description	AEO handling	Basis
D.	Energy Policy Act of 2005	Established a program to provide grants to enhance oil and gas recovery through CO2 injection.	Additional oil resources were added to account for increased use of CO2-enhanced oil recovery.	Title III, Section 354 of the Energy Policy Act of 2005.
E.	Section 29 Tax Credit for Nonconventional Fuels	The Alternative Fuel Production Credit (Section 29 of the IRC) applies to qualified nonconventional fuels from wells drilled or facilities placed in service between January 1, 1980, and December 31, 1992. Gas production from qualifying wells could receive a $3 (1979 constant dollars) per barrel of oil equivalent credit on volumes produced through December 31, 2002. The qualified fuels are: oil produced from shale and tar sands; gas from geopressurized brine, Devonian shale, coal seams, tight formations, and biomass; liquid, gaseous, or solid synthetic fuels produced from coal; fuel from qualified processed formations or biomass; and steam from agricultural products.	The Section 29 Tax Credit expired on December 31, 2002, and it not considered in new production decisions. However, the effect of these credits is implicitly included in the parameters that are derived from historical data reflecting such credits.	Alternative Fuel Production Credit (Section 29 of the Internal Revenue Code), initially established in the Windfall Profit Tax of 1980.
F.	Energy Policy Act of 2005	Established a program to provide grants to enhance oil and gas recovery through CO_2 injection.	Additional oil resources were added to account for increased use of CO_2-enhanced oil recovery.	Title III, Section 354 of the Energy Policy Act of 2005.
	Natural gas transmission and distribution			
A.	Alaska Natural Gas Pipeline Act, Sections 101-116 of the Military Construction Hurricane Supplemental Appropriations Act, 2005.	Disallows approval for a pipeline to enter Canada via Alaska north of 68 degrees latitude. Also, provides Federal guarantees for loans and other debt obligations assigned to infrastructure in the United States or Canada related to any natural gas pipeline system that carries Alaska natural gas to the border between Alaska and Canada south of 68 degrees north latitude. This authority would expire 2 years after the final certificate of public convenience and necessity is issued. The guarantee will not exceed 1) 80 percent of the total capital costs (including interest during construction), 2) $18 billion dollars (indexed for inflation at the time of enactment), or 3) a term of 30 years.	Assumes the pipeline construction cost estimate for the "southern"Alaska pipeline route in projecting when an Alaska gas pipeline would be profitable to build. With recent increased in cost estimates, well beyond $18 billion, the loan guarantee is assumed to have a minimal impact on the build decision.	P.L. 108-324.
B.	American Jobs Creation Act of 2004, Sections 706 and 707.	Provides a 7 year cost-of-investment recovery period for the Alaska natural gas pipeline, as opposed to the currently allowed 15-year recovery period, for tax purposes. The provision would be effective for property placed in service after 2013, or treated as such. Effectively extends the 15-percent tax credit currently applied to costs related to enhanced oil recovery to construction costs for a gas treatment plant on the on the North Slope that would feed gas into an Alaska pipeline to Canada.	The change in the recovery period is assumed to have a minimal impact on the decision to build the pipeline. The assumed treatment costs are based on company estimates made after these tax provisions were enacted.	P.L. 108-357.

	Legislation	Brief description	AEO handling	Basis
C.	Pipeline Safety Improvement Act of 2002	Imposes a stricter regime on pipeline operators designed to prevent leaks and ruptures.	Costs associated with implementing the new safety features are assumed to be a small percentage of total pipeline costs and are partially offset by benefits gained through reducing pipeline leakage. It is assumed that the Act accelerates the schedule of repair work that would have been done otherwise.	P.L. 107-355, 116 Stat. 2985.
D.	FERC Order 436 (Issued in 1985)	Order 436 changed gas transmission from a merchant business, wherein the pipeline buys the gas commodity at the inlet and sold the gas commodity at the delivery point, to being a transportation business wherein the pipeline does not take title to the gas . Order 436 permitted pipelines to apply for blanket transportation certificates, in return for becoming nondiscriminatory, open-access transporters. Order 436 also allocated gas pipeline capacity on a first-com, first-serve basis, allowed pipelines to discount below the maximum rate, allowed local gas distributors to convert to transportation only contracts, and created optional expedited certificates for the construction of new facilities.	Natural gas is priced at the wellhead at a competitive rate determined by the market. The flow of gas in the system is a function of the relative costs and is set to balance supply, demand, and prices in the market. Transportation costs are based on a regulated rate calculation.	50 F. R. 42408, FERC Statutes and Regulations Paragraph 30,665 (1985).
E.	FERC Order 636 (Issued in 1992)	FERC Order 636 completed the separation of pipeline merchant services from pipeline transportation services, requiring pipelines to offer separate tariffs for firm transportation, interruptible transportation, and storage services. Order 636 also permitted pipelines to resell unused firm capacity as interruptible transportation, gave shippers the right to first refusal at the expiration of their firm transportation contracts, adopted Straight-Fixed-Variable rate methodology, and created a mechanism for pipelines to recover the costs incurred by prior take-or-pay contracts.	A straight-fixed-variable rate design is used to establish regulated rates. To reflect some of the flexibility built into the system, the actual tariffs charged are allowed to vary from the regulated rates as a function of the utilization of the pipeline. End-use prices are set separately for firm and interruptible customers for the industrial and electric generation sectors.	57 F.R. 13267, FERC Statutes and Regulations Paragraph 30,939 (1992)
F.	Hackberry Decision	Terminated open access requirements for new onshore LNG terminals and authorized them to charge market-based rather than cost-of-service rates.	This is reflected in the structural representation of U.S. LNG imports in EIA's International Natural Gas Model, used to develop U.S. LNG import supply curves for the NGTDM.	Docket No. PL02-9, Natural Gas Markets Conference (2002).
G.	Maritime Security Act of 2002 Amendments to the Deepwater Port Act of 1974	Transfers jurisdiction over offshore LNG facilities from FERC to the Maritime Administration (MARAD) and the Coast Guard, both under	This is reflected in the structural representation of U.S. LNG imports in EIA's International Natural Gas Model, used to develop U.S. LNG import supply curves for the NGTDM.	P.L. 107-295.

	Legislation	Brief description	AEO handling	Basis
		the Department of Transportation (DOT), provides these facilities with a new, streamlined application process, and relaxes regulatory requirements (offshore LNG facilities are no longer required to operate as common carriers or to provide open access as they did while under FERC jurisdiction).		
H.	Energy Policy Act of 2005	Allowed natural gas storage facilities to charge market based rates if it was believed they would not exert market power.	Storage rates are allowed to vary from regulation-based rates depending on market conditions.	Title III, Section 312 of the Energy Policy Act of 2005.
	Petroleum refining			
A.	Ultra-Low Sulfur Diesel (ULSD) regulations under the Clean Air Act Amendment of 1990	80 percent of highway diesel pool must contain 15 ppm sulfur or less starting in fall 2006. By mid-2010, all highway diesel must be 15 ppm or less. All nonroad, locomotive, and marine diesel fuel produced must contain less than 500 ppm starting mid-2007. By mid-2010 nonroad diesel must contain less than 15 ppm. Locomotive and marine diesel must contain less than 15 ppm by mid-2012.	Reflected in diesel specifications.	40 CFR Parts 69, 80, 86, 89, 94, 1039, 1048, 1065, and 1068.
B.	Mobile Source Air Toxics (MSAT) Controls Under the Clean Air Act Amendment of 1990	Establishes a list of 21 substances emitted from motor vehicles and known to cause serious human health effects, particularly benzene, formaldehyde, 1.3 butadiene, acetaldehyde, diesel exhaust organic gases, and diesel particulate matter. Establishes anti-backsliding and anti-dumping rules for gasoline.	Modeled by updating gasoline specifications to most current EPA gasoline survey data (2005) representing anti-backsliding requirements.	40 CFR Parts 60 and 86.
C.	Low-Sulfur Gasoline Regulations Under the Clean Air Act Amendment of 1990	Gasoline must contain an average of 30 ppm sulfur or less by 2006. Small refiners may be permitted to delay compliance until 2008.	Reflected in gasoline specifications.	40 CFR Parts 80, 85 and 86.
D.	MTBE Bans in 25 States	23 States ban the use of MTBE in gasoline by 2007.	Ethanol assumed to be the oxygenate of choice in RFG where MTBE is banned	State laws in Arizona, California, Colorado, Connecticut, Illinois, Indiana, Iowa, Kansas, Kentucky, Maine, Michigan, Minnesota, Missouri, Montana, Nebraska, New Hampshire, New Jersey, New York, North Carolina, Ohio, Rhode Island, South Dakota, Vermont, Washington, and Wisconsin.
E.	Regional Clean Fuel Formulations	States with air quality problems can specify alternative gasoline or diesel formulations with EPA's permission. California has long had authority to set its own fuel standards.	Reflected in PADD-level gasoline and diesel specifications.	State implementation plans required by the Clean Air Act Amendments of 1990, as approved by EPA.

	Legislation	Brief description	AEO handling	Basis
F.	Federal Motor Fuels Excise Taxes	Taxes are levied on each gallon of transportation fuels to fund infrastructure and general revenue. These taxes are set to expire at various times in the future but are expected to be renewed, as they have been in the past.	Gasoline, diesel, and ethanol blend tax rates are included in end-use prices and are assumed to be extended indefinitely at current nominal rates.	26 USC 4041 Extended by American Jobs Creation Act of 2004
G.	State Motor Fuel Taxes	Taxes are levied on each gallon of transportation fuels. The assumption that State taxes will increase at the rate of inflation supports an implied need for additional highway revenues as driving increases.	Gasoline and diesel rates are included in end-use prices and are assumed to be extended indefinitely in real terms (to keep pace with inflation).	Determined by review of existing State laws performed semi-annually by EIA's Office of Energy Statistics.
H.	Diesel Excise Taxes	Phases out the 4.3 cents excise tax on railroads between 2005 and 2007.	Modeled by phasing out.	American Jobs Creation Act of 2004, Section 241.
I.	Energy Policy Act of 2005 (EPACT05)			
	a. Ethanol/biodiesel tax credit	Petroleum product blenders may claim tax credits for blending ethanol into gasoline and for blending biodiesel into diesel fuel or heating oil. The credits may be claimed against the Federal motor fuels excise tax or the income tax. The tax credits are 51 per gallon of nonvirgin biodiesel, and $1.00 per gallon of virgin biodiesel. The ethanol tax credit expires in 2010. The biodiesel tax credits expire after 2008.	The tax credits are applied against the production costs of the products into which they are blended. Ethanol is used in gasoline and E85. Virgin biodiesel is assumed to be blended into highway diesel, and nonvirgin biodiesel is assumed to be blended into nonroad diesel or heating oil.	26 USC 40, 4041 and American Jobs Creation Act of 2004. Biodiesel tax credits extended to 2008 under Energy Policy Act of 2005.
	b. Renewable Fuels Standard (RFS)	This section has largely been redefined by EISA07 (see below) however EPA rulemaking completed for this law was assumed to contain guiding principles of rthe rules and administration of EISA07.		Energy Policy Act of 2005, Section 1501.
	c. Elimination of oxygen content requirement in reformulated gasoline	Within 270 days of enactment of the Act, except for California where it is effective immediately.	Oxygenate waiver already an option of the model. MTBE is assumed to phase out in 2006 resulting from the petroleum industry''s decision to discontinue use. AEO projection may still show use of ethanol in gasoline based on the economics between ethanol and other gasoline blending components.	Energy Policy Act of 2005, Section 1504.
	d. Coal gasification provisions	Investment tax credit program for qualifying advanced clean coal projects including Coal-to-Liquids Projects.	Two CTL units are available to build with lower capital costs reflecting the provision's funding.	Energy Policy Act of 2005, Section 1307.

	Legislation	Brief description	AEO handling	Basis
J.	Energy Independence and Security Act of 2007 (EISA07)			
	a. Renewable Fuels Standard (RFS)	Requires the use of 36 billion gallons of ethanol per year by 2022, with corn ethanol limited to 15 billion gallons. Any other biofuel may be used to fulfill the balance of the mandate, but the balance must include 16 billion gallons per year of cellulosic biofuel by 2022 and 1 billion gallons per year of biodiesel by 2012.	The RFS is included in *AEO2011*, however it is assumed that the schedule for cellulosic biofuel is adjusted downward consistent with waiver provisions contained in the law.	
K.	State Heating Oil Mandates	A number of Northeastern States passed legislation that reduces the maximum sulfur content of heating oil to between 15 and 50 ppm in different phases through 2016.	All State regulations included as legislated in *AEO2011*. 2008 EIA Heating Oil consumption data used to calculate respective State/Census Division shares for new consumption of low sulfur diesel as heating oil.	Connecticut State Senate Bill 382, Maine State Legislature HP1160, NJ State Department of Environmental Protection, Amendment N.J.A.C. 7:27-9.2, New York State Senate Bill S1145C.
L.	California Low Carbon Fuel Standard (LCFS)	California passed legislation which is designed to reduce the Carbon Intensity (CI) of motor gasoline and diesel fuels sold in California by 10 percent between 2012 and 2020 through the increased sale of alternative "low-carbon" fuels.	The LCFS is included in *AEO2011* as legislated for gasoline and diesel fuel sold in California, and for other regulated fuels. The Pacific Census Division 9 was used as a proxy.	California Air Resources Board, "Final Regulation Order: Subarticle 7. Low Carbon Fuel Standard."
M.	EPA ETS Waiver	EPA approved two waivers for the use of ethanol motor gasoline blends of up to 15 percent in vehicles 2001 and newer.	These two waivers were included and modeled in *AEO2011* based on forecasted vehicle fleets and potential infrastructure and liability setbacks.	EPA-HQ-OAR-2009-0211; FRL-9215-5, EPA-HQ-OAR-2009-0211; FRL-9258-6.
	Coal supply			
A.	April 1, 2010 Memorandum: Improving EPA Review of Appalachian Surface Coal Mining Operations Under the Clean Water Act, National Environmental Policy Act, and the Environmental Justice Executive Order	On April 1, 2010, the EPA issued a set of interim guidelines to several of its regional offices for monitoring the compliance of surface coal mining operations in Appalachia. The guidelines relate primarily to the ongoing controversy over use of the mountaintop removal method at a number of surface coal mining operations in Central Appalachia primarily in southern West Virginia and eastern Kentucky. While the guidelines propose a more rigorous review for all new surface coal mines in Appalachia, the EPA indicates that the practice of valley fills, primarily associated with the mountaintop removal method, is the aspect of Appalachian coal mining that will be most scrutinized.	The impact of the EPA's interim guidelines for surface coal mining operations in Appalachia is represented by downward adjustments to the coal mining productivity assumptions for Central Appalachian surface mines. The revised productivity levels, which are roughly 15 to 20 percent lower than those that would have been used for a case without the EPA's new permit review guidelines, are based on the assumption that average productivity for surface mining operations. Central Appalachia will decline gradually toward the productivity levels for smaller surface mines in the region as a result of the more restrictive guidelines for overburden management at large mountaintop mining operations.	Permit program for discharges of dredged or fill material, which is administered primarily by the U.S. Army Corps of Engineers pursuant to Section 404 of the CWA, 33 U.S.C. 1344; the National Pollutant Discharge Elimination System (NPDES), which is administered by the EPA and authorized States pursuant to Section 402 of the CWA, 33 U.S.C. 1342; the National Environmental Policy Act; and the Environmental Justice Executive Order (E.O. 12898)

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Abbreviations:

AEO: Annual Energy Outlook
AFUE: Average Fuel Use Efficiency
Btu: British Thermal Unit
CAFE: Corporate Average Fuel Economy
CBECS : Commercial Building Energy Consumption Survey
CFR : Code of Feder al Regulations
DOE : U.S. Department of Energy
DOT: Department of Transportation
DWRRA: Deep Water Royalty Relief Act
EER: Energy Efficient Ratio
EF: Energy Efficiency
E IA: U.S. Energy Information Administration
E PA: U.S. Environmental Protection Agency
EPAC T92: Energy Polic y Act of 1992
EPAC T05: Energy Policy Act of 2005
EWGs: Exempt Wholesale Generators
FERC: Federal Energy Regulatory Commission
H ERS: Home Energy Efficiency Rating
HVAC: Heating, Ventilation, and Air Conditioning IECC: International Energy Conservation Code ITC: Investment Tax Credit
kWh: Kilowatthour
LBNL: Lawrence Berkeley National Laboratory
LE VP: Low Emission Vehicle Program
LNG : Liquified Natural Gas
MARAD : Maritime Administration
MCF: Thousand Cubic Feet
MEF : Modified Energy Factor
MSAT: Mobile Source Air Toxics
MTBE: Methyl-Tertiary-Butyl-Ether
OASIS: Open Access Same-Time Information System
PADD : Petroleum Administration for Defense Districts
P.L.: Public Law
PPM: Parts Per Million
PTC : Production Tax Credit
PUCHA : Public Utility Holding Company Act of 1935
RECS: Residential Energy Consumption Survey
RPS: Renewable Portfolio Standard
SCR: Selective Catalytic Reduction
SEER: Seasonal Energy Efficiency Rating
SO2: Sulfur Dioxide
SNCR: Selective Non-Catalytic Reduction
ULSD: Ultra-Low Sulfur Dioesel
U.S.C .: United States Code
USG S: United States Geological Survey
ZEV: Zero Emission Vehicle

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